

WHITING PETROLEUM CORP  
Form 10-Q  
July 30, 2009

---

---

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2009

or

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

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

Delaware  
(State or other jurisdiction of  
incorporation or organization)

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

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

80290-2300  
(Zip code)

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

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

Edgar Filing: WHITING PETROLEUM CORP - Form 10-Q

(§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

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

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

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

Number of shares of the registrant’s common stock outstanding at July 15, 2009: 50,841,572 shares.

---

## TABLE OF CONTENTS

<u>Certain Definitions</u>		<u>1</u>
<u>PART I — FINANCIAL INFORMATION</u>		
<u>Item 1.</u>	<u>Consolidated Financial Statements (Unaudited)</u>	<u>2</u>
	<u>Consolidated Balance Sheets as of June 30, 2009 and December 31, 2008</u>	<u>2</u>
	<u>Consolidated Statements of Income for the Three and Six Months Ended June 30, 2009 and 2008</u>	<u>4</u>
	<u>Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2009 and 2008</u>	<u>5</u>
	<u>Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Year Ended December 31, 2008 and the Six Months Ended June 30, 2009</u>	<u>6</u>
	<u>Notes to Consolidated Financial Statements</u>	<u>7</u>
<u>Item 2.</u>	<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	<u>22</u>
<u>Item 3.</u>	<u>Quantitative and Qualitative Disclosures about Market Risk</u>	<u>40</u>
<u>Item 4.</u>	<u>Controls and Procedures</u>	<u>42</u>
<u>PART II — OTHER INFORMATION</u>		
<u>Item 1.</u>	<u>Legal Proceedings</u>	<u>43</u>
<u>Item 1A.</u>	<u>Risk Factors</u>	<u>43</u>
<u>Item 4.</u>	<u>Submission of Matters to a Vote of Security Holders</u>	<u>56</u>
<u>Item 6.</u>	<u>Exhibits</u>	<u>56</u>
	<u>Certification by the Chairman, President and Chief Executive Officer</u>	
	<u>Certification by the Vice President and Chief Financial Officer</u>	
	<u>Written Statement of the Chairman, President and Chief Executive Officer</u>	
	<u>Written Statement of the Vice President and Chief Financial Officer</u>	

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.

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

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

“MBOE” - One thousand BOE.

“MBOE/d” - One 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, 2009	December 31, 2008
<b>ASSETS</b>		
<b>CURRENT ASSETS:</b>		
Cash and cash equivalents	\$ 13,178	\$ 9,624
Accounts receivable trade, net	106,880	123,386
Derivative assets	8,714	46,780
Prepaid expenses and other	10,978	37,284
<b>Total current assets</b>	<b>139,750</b>	<b>217,074</b>
<b>PROPERTY AND EQUIPMENT:</b>		
Oil and gas properties, successful efforts method:		
Proved properties	4,632,721	4,423,197
Unproved properties	99,773	106,436
Other property and equipment	125,534	91,099
<b>Total property and equipment</b>	<b>4,858,028</b>	<b>4,620,732</b>
Less accumulated depreciation, depletion and amortization	(1,081,323)	(886,065)
<b>Total property and equipment, net</b>	<b>3,776,705</b>	<b>3,734,667</b>
<b>DEBT ISSUANCE COSTS</b>	<b>29,708</b>	<b>10,779</b>
<b>DERIVATIVE ASSETS</b>	<b>13,520</b>	<b>38,104</b>
<b>OTHER LONG-TERM ASSETS</b>	<b>26,273</b>	<b>28,457</b>
<b>TOTAL</b>	<b>\$ 3,985,956</b>	<b>\$ 4,029,081</b>

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, 2009	December 31, 2008
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
<b>CURRENT LIABILITIES:</b>		
Accounts payable	\$ 25,359	\$ 64,610
Accrued capital expenditures	22,462	84,960
Accrued liabilities	63,879	45,359
Accrued interest	11,101	9,673
Oil and gas sales payable	30,579	35,106
Accrued employee compensation and benefits	9,566	41,911
Production taxes payable	17,755	20,038
Deferred gain on sale	13,543	14,650
Derivative liabilities	34,362	17,354
Deferred income taxes	13,115	15,395
Tax sharing liability	2,112	2,112
<b>Total current liabilities</b>	<b>243,833</b>	<b>351,168</b>
<b>NON-CURRENT LIABILITIES:</b>		
Long-term debt	839,565	1,239,751
Deferred income taxes	325,002	390,902
Deferred gain on sale	66,028	73,216
Production Participation Plan liability	69,846	66,166
Asset retirement obligations	60,898	47,892
Derivative liabilities	97,894	28,131
Tax sharing liability	22,393	21,575
Other long-term liabilities	3,217	1,489
<b>Total non-current liabilities</b>	<b>1,484,843</b>	<b>1,869,122</b>
<b>COMMITMENTS AND CONTINGENCIES</b>		
<b>STOCKHOLDERS' EQUITY:</b>		
Preferred stock, \$0.001 par value, 5,000,000 shares authorized;		
6.25% convertible perpetual preferred stock, 3,450,000 and 0 shares issued and outstanding as of June 30, 2009 and December 31, 2008, respectively, aggregate liquidation preference of \$345,000,000	3	-
Common stock, \$0.001 par value, 75,000,000 shares authorized;		
51,365,790 issued and 50,843,532 outstanding as of June 30, 2009 and 42,582,100 issued and 42,323,336 outstanding as of December 31, 2008	51	43
Additional paid-in capital	1,542,022	971,310
Accumulated other comprehensive income	31,959	17,271
Retained earnings	683,245	820,167

Edgar Filing: WHITING PETROLEUM CORP - Form 10-Q

Total stockholders' equity		2,257,280		1,808,791
<b>TOTAL</b>	<b>\$</b>	<b>3,985,956</b>	<b>\$</b>	<b>4,029,081</b>

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,		Six Months Ended June 30,	
	2009	2008	2009	2008
<b>REVENUES AND OTHER INCOME:</b>				
Oil and natural gas sales	\$ 214,303	\$ 390,536	\$ 360,478	\$ 677,267
Gain (loss) on oil hedging activities	6,848	(48,111)	20,298	(71,023)
Amortization of deferred gain on sale	4,274	2,957	8,373	2,957
Gain on sale of properties	4,608	-	4,608	-
Interest income and other	125	393	240	624
Total revenues and other income	230,158	345,775	393,997	609,825
<b>COSTS AND EXPENSES:</b>				
Lease operating	57,582	57,470	118,536	113,176
Production taxes	14,914	26,057	24,433	43,743
Depreciation, depletion and amortization	100,315	54,811	200,349	105,322
Exploration and impairment	9,792	8,643	27,106	19,627
General and administrative	10,282	23,007	19,262	34,622
Interest expense	18,693	15,671	33,373	31,217
Change in Production Participation Plan liability	3,284	11,690	3,680	17,847
Loss on mark-to-market derivatives	160,532	20,562	182,297	17,625
Total costs and expenses	375,394	217,911	609,036	383,179
<b>INCOME (LOSS) BEFORE INCOME TAXES</b>	<b>(145,236)</b>	<b>127,864</b>	<b>(215,039)</b>	<b>226,646</b>
<b>INCOME TAX EXPENSE (BENEFIT):</b>				
Current	-	(837)	(539)	872
Deferred	(52,073)	48,252	(77,578)	83,011
Total income tax expense (benefit)	(52,073)	47,415	(78,117)	83,883
<b>NET INCOME (LOSS)</b>	<b>(93,163)</b>	<b>80,449</b>	<b>(136,922)</b>	<b>142,763</b>
Preferred stock dividends	-	-	-	-
<b>NET INCOME (LOSS) AVAILABLE (APPLICABLE) TO COMMON SHAREHOLDERS</b>				
	\$ (93,163)	\$ 80,449	\$ (136,922)	\$ 142,763
	\$ (1.83)	\$ 1.90	\$ (2.78)	\$ 3.38



NET INCOME (LOSS) PER  
COMMON SHARE, BASIC

NET INCOME (LOSS) PER COMMON SHARE, DILUTED	\$	(1.83)	\$	1.90	\$	(2.78)	\$	3.37
--	----	--------	----	------	----	--------	----	------

WEIGHTED AVERAGE  
SHARES OUTSTANDING,  
BASIC

	50,842	42,320	49,230	42,296
--	--------	--------	--------	--------

WEIGHTED AVERAGE  
SHARES OUTSTANDING,  
DILUTED

	50,842	42,446	49,230	42,416
--	--------	--------	--------	--------

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,	
	2009	2008
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>		
Net income (loss)	\$ (136,922)	\$ 142,763
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	200,349	105,322
Deferred income tax (benefit) expense	(77,578)	83,011
Amortization of debt issuance costs and debt discount	4,355	2,423
Accretion of tax sharing liability	819	623
Stock-based compensation	2,577	3,245
Amortization of deferred gain on sale	(8,373)	(2,957)
Gain on sale of properties	(4,608)	-
Undeveloped leasehold and oil and gas property impairments	8,295	5,400
Change in Production Participation Plan liability	3,680	17,847
Unrealized loss on derivative contracts	172,991	17,625
Other non-current	(2,754)	(11,757)
Changes in current assets and liabilities:		
Accounts receivable trade	17,866	(80,853)
Prepaid expenses and other	26,306	(24,472)
Accounts payable and accrued liabilities	(24,321)	43,060
Accrued interest	1,428	(607)
Other current liabilities	(39,808)	28,418
Net cash provided by operating activities	144,302	329,091
<b>CASH FLOWS FROM INVESTING ACTIVITIES:</b>		
Cash acquisition capital expenditures	(38,691)	(388,457)
Drilling and development capital expenditures	(327,840)	(376,410)
Proceeds from sale of oil and gas properties	79,609	311
Proceeds from sale of marketable securities	-	764
Net proceeds from sale of 11,677,500 units in Whiting USA Trust I	-	195,128
Net cash used in investing activities	(286,922)	(568,664)
<b>CASH FLOWS FROM FINANCING ACTIVITIES:</b>		
Issuance of 6.25% convertible perpetual preferred stock	334,562	-
Issuance of common stock	234,753	-
Long-term borrowings under credit agreement	260,000	735,000
Repayments of long-term borrowings under credit agreement	(660,000)	(485,000)
Debt issuance costs	(23,141)	-
Net cash provided by financing activities	146,174	250,000
<b>NET CHANGE IN CASH AND CASH EQUIVALENTS</b>	<b>3,554</b>	<b>10,427</b>
<b>CASH AND CASH EQUIVALENTS:</b>		
Beginning of period	9,624	14,778
End of period	\$ 13,178	\$ 25,205
<b>SUPPLEMENTAL CASH FLOW DISCLOSURES:</b>		
Cash paid (refunded) for income taxes	\$ (2,484)	\$ 832
Cash paid for interest	\$ 26,771	\$ 28,778
<b>NONCASH INVESTING ACTIVITIES:</b>		

Accrued capital expenditures during the period	\$	22,462	\$	73,658
--	----	--------	----	--------

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	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity	Comprehensive Income (Loss)		
	Shares	Amount	Shares	Amount	Capital	(Loss)	Earnings	Equity	(Loss)
<b>BALANCES-January 1, 2008</b>	-	\$ -	42,480	\$ 42	\$ 968,876	\$ (46,116)	\$ 568,024	\$ 1,490,826	
Net income	-	-	-	-	-	-	142,763	142,763	\$ 142,763
Change in derivative fair values, net of taxes of \$46,279	-	-	-	-	-	(79,993)	-	(79,993)	(79,993)
Realized loss on settled derivative contracts, net of taxes of \$26,021	-	-	-	-	-	44,978	-	44,978	44,978
<b>Total comprehensive income</b>									<b>\$ 107,748</b>
Restricted stock issued	-	-	139	1	-	-	-	1	
Restricted stock forfeited	-	-	(3)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(30)	-	(1,734)	-	-	(1,734)	
Stock-based compensation	-	-	-	-	3,245	-	-	3,245	
<b>BALANCES-June 30, 2008</b>	-	-	42,586	\$ 43	\$ 970,387	\$ (81,131)	\$ 710,787	\$ 1,600,086	
<b>BALANCES-December 31, 2008</b>	-	\$ -	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 \$7,706	-	-	-	-	-	13,302	-	13,302	13,302
Realized gain on settled derivatives, net of taxes of \$4,933	-	-	-	-	-	(8,517)	-	(8,517)	(8,517)
Ineffectiveness loss on hedging activities, net of taxes of \$8,387	-	-	-	-	-	14,479	-	14,479	14,479
OCI amortization on de-designated hedges, net of taxes of \$2,272	-	-	-	-	-	(4,576)	-	(4,576)	(4,576)
<b>Total comprehensive loss</b>									<b>\$ (122,234)</b>

Edgar Filing: WHITING PETROLEUM CORP - Form 10-Q

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
<b>BALANCES-June 30, 2009</b>	<b>3,450</b>	<b>\$ 3</b>	<b>51,366</b>	<b>\$ 51</b>	<b>\$ 1,542,022</b>	<b>\$ 31,959</b>	<b>\$ 683,245</b>	<b>\$ 2,257,280</b>

See notes to consolidated financial statements.

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. Whiting’s 2008 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. Except as disclosed herein, there has been no material change to the information disclosed in the notes to the consolidated financial statements included in Whiting’s 2008 Annual Report on Form 10-K. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Earnings Per Share—Basic net income per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted net income per common share is calculated by dividing adjusted net income by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method, and convertible perpetual preferred stock using the if-converted method. All potentially dilutive securities are anti-dilutive when a loss from continuing operations exists and are excluded from the computation of diluted earnings per share accordingly.

Subsequent Events—The Company has evaluated subsequent events through the date the financial statements were issued and has no material subsequent events to report.

2. ACQUISITIONS AND DIVESTITURES

2009 Acquisitions

There were no significant acquisitions during the first half of 2009.

Table of Contents

## 2009 Participation Agreement

On June 4, 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.

As of June 4, 2009, there were 18 wells drilled or in the process of being drilled on the 26 units covered by the agreement and 12 more wells planned in 2009 on these units. 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 the 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. Estimated proved reserves of 2.8 MMBOE, as of June 1, 2009, were sold by the Company as a result of this divestiture.

## 2008 Acquisition

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

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

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

Acquisition Pro Forma—In the Company's consolidated statements of income for the year ended December 31, 2008, Flat Rock's results of operations are included with the Company's results beginning May 31, 2008. The following table, however, reflects the unaudited pro forma results of operations for the three and six months ended June 30, 2008, as though the Flat Rock acquisition had occurred on the first day of each period. The pro forma information below includes numerous assumptions and is not necessarily indicative of what historical results would have been or what future results of operations will be.

Table of Contents

	Pro Forma		
	Whiting (As reported)	Flat Rock	Consolidated
Three months ended June 30, 2008:			
Total revenues	\$ 345,775	\$ 7,879	\$ 353,654
Net income	80,449	850	81,299
Net income per common share – basic and diluted	\$ 1.90	\$ 0.02	\$ 1.92
Six months ended June 30, 2008:			
Total revenues	\$ 609,825	\$ 17,761	\$ 627,586
Net income	142,763	1,144	143,907
Net income per common share – basic	\$ 3.38	\$ 0.02	\$ 3.40
Net income per common share – diluted	\$ 3.37	\$ 0.02	\$ 3.39

## 2008 Divestiture

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

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

## 3. LONG-TERM DEBT

Long-term debt consisted of the following at June 30, 2009 and December 31, 2008 (in thousands):

	June 30, 2009	December 31, 2008
Credit Agreement	\$ 220,000	\$ 620,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of \$1,341 and \$1,541, respectively	218,659	218,459
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of \$331 and \$397, respectively	150,906	151,292
Total debt	\$ 839,565	\$ 1,239,751



Table of Contents

Credit Agreement—As of June 30, 2009, Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), the Company’s wholly-owned subsidiary, had a credit agreement with a syndicate of banks that had a borrowing base of \$1.1 billion with \$877.2 million of available borrowing capacity, which is net of \$220.0 million in borrowings and \$2.8 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2012, when the entire amount is due. In April 2009, Whiting Oil and Gas entered into a Fourth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit agreement. This amended credit agreement increased the Company’s borrowing base under the facility from \$900.0 million to \$1.1 billion and extended the principal repayment date from August 2010 to April 2012.

The borrowing base under the renewed 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, 2009, \$47.2 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, and are included as a component of interest expense. At June 30, 2009, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.3%.

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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 4.5 to 1.0 for quarters ending prior to and on September 30, 2010, 4.25 to 1.0 for quarters ending December 31, 2010 to June 30, 2011 and 4.0 to 1.0 for quarters ending September 30, 2011 and thereafter, (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement 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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and 2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. Except for limited exceptions, 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 dividends 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, 2009.

10

---

Table of Contents

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

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 \$230.0 million as of June 30, 2009, based on quoted market prices for these same debt securities.

In April 2005, the Company issued \$220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of \$3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was \$207.9 million as of June 30, 2009, based on quoted market prices for these same debt securities.

In May 2004, the Company issued \$150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of \$1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.3%. The estimated fair value of these notes was \$143.3 million as of June 30, 2009, based on quoted market prices for these same debt securities.

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

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of \$75.0 million of its 7.25% Senior Subordinated Notes due 2012. The interest rate swap was a fixed for floating swap in that the Company received the fixed rate of 7.25% and paid the floating rate. In March 2009, the counterparty exercised its option to cancel the swap contract effective May 1, 2009, resulting in a cancellation fee of \$1.4 million paid to the Company.

#### 4. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California), in accordance with applicable local, state and federal laws. The Company determines asset retirement obligations by calculating the present value of estimated cash flows related to plug and abandonment obligations. The current portions at June 30, 2009 and December 31, 2008 were \$10.0 million and \$6.5 million, respectively, and were recorded in accrued liabilities.

Table of Contents

The following table provides a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2009 (in thousands):

Asset retirement obligation, January 1, 2009	\$ 54,348
Additional liability incurred	334
Revisions in estimated cash flows	16,195
Accretion expense	3,757
Obligations on sold properties	(94)
Liabilities settled	(3,596)
Asset retirement obligation, June 30, 2009	\$ 70,944

## 5. DERIVATIVE FINANCIAL INSTRUMENTS

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

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

Whiting derivatives—The table below details the Company's costless collar derivatives, including its proportionate share of Trust hedges, entered into to hedge forecasted crude oil and natural gas production revenues, as of July 7, 2009.

Period	Whiting Petroleum Corporation			
	Contracted Volumes		NYMEX Price Collar Ranges	
	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2009	2,990,063	274,646	\$ 60.53 - \$ 77.78	\$ 6.49 - \$ 15.23
Jan – Dec 2010	5,046,289	495,390	\$ 62.34 - \$ 83.00	\$ 6.50 - \$ 15.06
Jan – Dec 2011	4,435,039	436,510	\$ 58.01 - \$ 89.37	\$ 6.50 - \$ 14.62
Jan – Dec 2012	4,065,091	384,002	\$ 57.70 - \$ 91.02	\$ 6.50 - \$ 14.27
Jan – Nov 2013	3,090,000	-	\$ 55.30 - \$ 85.68	n/a
Total	19,626,482	1,590,548		

Derivatives conveyed to Whiting USA Trust I—In connection with the Company's conveyance on April 30, 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust units to the public (as further explained in the note on Acquisitions and Divestitures), the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to the Trust, and therefore such payments will be included in the Trust's

calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's retention of 10% of these net proceeds, combined with its ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of commodity derivative contracts conveyed to the Trust. The relative ownership of the future economic results of such commodity derivatives is reflected in the tables below. No additional hedges are allowed to be placed on Trust assets.

Table of Contents

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:

Period	Whiting Petroleum Corporation Contracted Volumes		NYMEX Price Collar Ranges	
	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2009	68,063	274,646	\$ 76.00 - \$ 136.07	\$ 6.49 - \$ 15.23
Jan – Dec 2010	126,289	495,390	\$ 76.00 - \$ 134.98	\$ 6.50 - \$ 15.06
Jan – Dec 2011	115,039	436,510	\$ 74.00 - \$ 140.15	\$ 6.50 - \$ 14.62
Jan – Dec 2012	105,091	384,002	\$ 74.00 - \$ 141.72	\$ 6.50 - \$ 14.27
<b>Total</b>	<b>414,482</b>	<b>1,590,548</b>		

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

Period	Third-party Public Holders of Trust Units Contracted Volumes		NYMEX Price Collar Ranges	
	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2009	213,188	860,254	\$ 76.00 - \$ 136.07	\$ 6.49 - \$ 15.23
Jan – Dec 2010	395,567	1,551,678	\$ 76.00 - \$ 134.98	\$ 6.50 - \$ 15.06
Jan – Dec 2011	360,329	1,367,249	\$ 74.00 - \$ 140.15	\$ 6.50 - \$ 14.62
Jan – Dec 2012	329,171	1,202,785	\$ 74.00 - \$ 141.72	\$ 6.50 - \$ 14.27
<b>Total</b>	<b>1,298,255</b>	<b>4,981,966</b>		

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.

Table of Contents

At March 31, 2009, accumulated other comprehensive income consisted of \$59.8 million (\$36.5 million after tax) of unrealized gains, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on April 1, 2009, such mark-to-market values at March 31, 2009 are frozen in accumulated other comprehensive income as of the de-designation date and reclassified into earnings as the original hedged transactions affect income. During the three and six months ended June 30, 2009, \$6.8 million (\$4.6 million net of tax) of derivative gains were reclassified from accumulated other comprehensive income into earnings relating to de-designated commodity hedges. As of June 30, 2009, accumulated other comprehensive income amounted to \$50.6 million (\$32.0 million net of tax), which consisted entirely of unrealized deferred gains on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of \$21.2 million related to de-designated commodity hedges during the next twelve months.

Interest rate derivative contract—In August 2004, the Company entered into an interest rate swap agreement to manage its exposure to interest rate risk on a portion of its fixed-rate borrowings. The interest rate swap effectively modified the Company's exposure to interest rate risk by converting the fixed rate on \$75.0 million of the Company's Senior Subordinated Notes due 2012 to a floating rate. This agreement involved the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The interest rate swap was designated as a fair value hedge. In March 2009, the counterparty exercised its option to cancel the swap contract effective May 1, 2009, resulting in a cancellation fee of \$1.4 million paid to the Company.

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

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

Designated as SFAS 133 Hedges	Balance Sheet Classification	Fair Value	
		June 30, 2009	December 31, 2008
Derivative assets			
Commodity contracts	Current derivative assets	\$ -	\$ 30,198
Commodity contracts	Non-current derivative assets	-	13,163
Interest rate swap contract	Other long-term assets	-	1,690
Total derivative assets		\$ -	\$ 45,051
Derivative liabilities			
Commodity contracts	Current derivative liabilities	\$ -	\$ 4,784
Commodity contracts	Non-current derivative liabilities	-	9,224
Total derivative liabilities		\$ -	\$ 14,008

Table of Contents

Not Designated as SFAS 133 Hedges		Balance Sheet Classification	Fair Value	
			June 30, 2009	December 31, 2008
Derivative assets				
Commodity contracts	Current derivative assets	\$	8,714	\$ 16,582
Commodity contracts	Non-current derivative assets		13,520	24,941
Total derivative assets			22,234	41,523
Derivative liabilities				
Commodity contracts	Current derivative liabilities	\$	34,362	\$ 12,570
Commodity contracts	Non-current derivative liabilities		97,894	18,907
Total derivative liabilities		\$	132,256	\$ 31,477

Commodity derivative contracts—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, 2009 and 2008 (in thousands).

SFAS 133 Cash Flow Hedging Relationships	Location of Gain (Loss) Not Recognized in Income	Gain (Loss) Recognized in OCI (Effective Portion) Six Months Ended June 30,	
		2009	2008
Commodity contracts	Other comprehensive income	\$ 21,008	\$ (126,272)

		Three Months Ended June 30,	
		2009	2008
Commodity contracts	Other comprehensive income	\$ -	\$ (104,895)

SFAS 133 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30,	
		2009	2008
Commodity contracts	Gain (loss) on oil hedging activities	\$ 20,298	\$ (71,023)

		Three Months Ended June 30,	
		2009	2008
Commodity contracts	Gain (loss) on oil hedging activities	\$ 6,848	\$ (48,111)



Table of Contents

SFAS 133 Cash Flow Hedging Relationships		(Gain) Loss Recognized in Income (Ineffective Portion) Six Months Ended June 30,	
		2009	2008
	Income Statement Classification		
	Loss on mark-to-market derivatives		
Commodity contracts		\$ 22,866	\$ -
		Three Months Ended June 30,	
		2009	2008
	Loss on mark-to-market derivatives		
Commodity contracts		\$ -	\$ -

Not Designated as SFAS 133 Hedges		(Gain) Loss Recognized in Income Six Months Ended June 30,	
		2009	2008
	Income Statement Classification		
	Loss on mark-to-market derivatives		
Commodity contracts		\$ 159,431	\$ 17,625
		Three Months Ended June 30,	
		2009	2008
	Loss on mark-to-market derivatives		
Commodity contracts		\$ 160,532	\$ 20,562

Fair value hedge—In March 2009, the Company's derivative counterparty exercised its option to cancel the Company's interest rate swap contract effective May 1, 2009. Prior to the cancellation, the gain or loss on the hedged item (\$75.0 million of fixed-rate borrowings under the Company's Senior Subordinated Notes due 2012) attributable to the hedged benchmark interest rate risk (risk of changes in the LIBOR swap rate) and the offsetting gain or loss on the related interest rate swap for the three and six months ended June 30, 2009 and 2008 were as follows (in thousands):

Income Statement Classification	Gain (Loss) on Swap Six Months Ended June 30,		Gain (Loss) on Borrowing Six Months Ended June 30,		
	2009	2008	2009	2008	
Interest expense	\$ (330)	\$ (125)	\$ 330	\$ 125	
		Three Months Ended June 30,			
		2009	2008	2009	2008
Interest expense	\$ -	\$ (1,730)	\$ -	\$ 1,730	

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

Contingent features in derivative instruments—None of the Company’s derivative instruments contain credit-risk-related contingent features. Counterparties to the Company’s derivative contracts are high credit quality financial institutions that are lenders under Whiting’s credit agreement. Whiting uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of Whiting’s bank debt which eliminates the potential need to post collateral when Whiting is in a large derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for the counterparty to secure contract performance obligations.

Table of Contents

## 6. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted FASB Statement No. 157, Fair Value Measurements (“SFAS 157”) which established a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

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

A financial instrument’s categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The following table presents information about the Company’s financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value June 30, 2009
<b>Financial Assets</b>				
Commodity derivatives - current	\$ -	\$ 8,714	\$ -	\$ 8,714
Commodity derivatives - non-current	-	13,520	-	13,520
<b>Total financial assets</b>	<b>\$ -</b>	<b>\$ 22,234</b>	<b>\$ -</b>	<b>\$ 22,234</b>
<b>Financial Liabilities</b>				
Commodity derivatives - current	\$ -	\$ 34,362	\$ -	\$ 34,362
Commodity derivatives - non-current	-	97,894	-	97,894
<b>Total financial liabilities</b>	<b>\$ -</b>	<b>\$ 132,256</b>	<b>\$ -</b>	<b>\$ 132,256</b>

**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 modeling techniques that consider the 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 designated as Level 2 within the valuation hierarchy. The discount rate used in the fair values of these instruments includes a measure of nonperformance risk. The Company utilizes the counterparties’ valuations to assess the reasonableness of its own valuations.

Table of Contents

## 7. DEFERRED COMPENSATION

Production Participation Plan—The Company has a Production Participation Plan (the “Plan”) in which all employees participate. On an annual basis, interests in oil and gas properties acquired, developed or sold during the year are allocated to the Plan as determined annually by the Compensation Committee. 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, 2009 and 2008 amounted to \$5.7 million and \$20.5 million, respectively, charged to general and administrative expense and \$0.8 million and \$3.3 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, 2009, the Company used three-year average historical NYMEX prices of \$78.63 for crude oil and \$7.17 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control (as defined in the Plan), all employees fully vest, and the Company would distribute to each Plan participant an amount based upon the valuation method set forth in the Plan in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on prices at June 30, 2009, if the Company elected to terminate the Plan or if a change of control event occurred, it is estimated that the fully vested lump sum cash payment to employees would approximate \$108.2 million. This amount includes \$17.7 million attributable to proved undeveloped oil and gas properties and \$6.5 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2010. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

The following table presents changes in the estimated long-term liability related to the Plan for the six months ended June 30, 2009 (in thousands):

Production Participation Plan liability, January 1, 2009	\$	66,166
Change in liability for accretion, vesting and changes in estimates		10,225
Reduction in liability for cash payments accrued and recognized as compensation expense		(6,545)
Production Participation Plan liability, June 30, 2009	\$	69,846

## 8. STOCKHOLDERS’ EQUITY

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 \$334.6 million after underwriters’ fees and offering expenses. The Company used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas’ credit agreement.



Table of Contents

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 with the first dividend payment September 15, 2009. 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 automatically converted into shares of common stock if certain conditions are met. 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 offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. Whiting plans to use the increased credit availability to fund a portion of the planned capital expenditures in its 2009 capital budget.

## 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, 2009 and 2008 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 acquired, additional information is obtained or as the tax environment changes.

## 10. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

Table of Contents

In June 2009, the FASB issued SFAS No. 168, The “FASB Accounting Standards Codification” and the Hierarchy of Generally Accepted Accounting Principles (“SFAS 168”). This standard replaces SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, and establishes only two levels of GAAP, authoritative and nonauthoritative. The FASB Accounting Standards Codification (the “Codification”) was not intended to change or alter existing GAAP, and it therefore will not have any impact on the Company’s consolidated financial statements other than to modify certain existing disclosures. The Codification will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. SFAS 168 is effective for financial statements for interim or annual reporting periods ending after September 15, 2009. The Company will begin to use the new guidelines and numbering system prescribed by the Codification when referring to GAAP in the third quarter of fiscal 2009.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (“SFAS 165”). This standard is intended to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, this standard sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS 165 is effective for fiscal years and interim periods ended after June 15, 2009. The Company adopted SFAS 165 effective April 1, 2009. The adoption of SFAS 165 did not have an impact on the Company’s consolidated financial statements, other than additional disclosures.

In April 2009, the FASB issued two FASB Staff Positions (“FSP”) intended to provide additional application guidance and enhanced disclosures regarding fair value measurements and impairments of securities. FSP No. FAS 157-4, Determining Fair Value When the Volume or Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly (“FSP 157-4”), provides additional guidelines for estimating fair value in accordance with SFAS No. 157, Fair Value Measurements. FSP No. 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (“FSP 107-1”), increases the frequency of fair value disclosures. These FSPs are effective for fiscal years and interim periods ended after June 15, 2009. The Company adopted these FSPs effective April 1, 2009. The adoption of these FSPs did not have an impact on the Company’s consolidated financial statements, other than additional disclosures.

The Company elected to implement SFAS 157 with the one-year deferral permitted by FSP No. FAS 157-2, Effective Date of FASB Statement No. 157 (“FSP 157-2”), issued February 2008, which deferred the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value. Accordingly, the Company adopted SFAS 157 on January 1, 2009 for its nonfinancial assets and nonfinancial liabilities measured at fair value on a non-recurring basis. This deferred adoption of SFAS 157, however, did not have an impact on the Company’s consolidated financial statements nor its disclosures. As it relates to the Company, this delayed adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used.

Table of Contents

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations (“SFAS 141(R)”), which replaces SFAS No. 141. SFAS 141(R) is effective for business combinations with acquisition dates on or after fiscal years beginning after December 15, 2008, and the Company adopted SFAS 141(R) effective January 1, 2009. As the Company has not entered into any business combinations during the first half of 2009, the adoption of SFAS 141(R) has not had any impact on the Company’s consolidated financial statements. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination.



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

Overview

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

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

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

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

## Table of Contents

Oil and natural gas prices have fallen significantly since their third quarter 2008 levels. For example, the daily average NYMEX oil price was \$118.13 per Bbl for the third quarter of 2008, \$58.75 per Bbl for the fourth quarter of 2008, and \$51.46 per Bbl for the first six months of 2009. Similarly, daily average NYMEX natural gas prices have declined from \$10.27 per Mcf for the third quarter of 2008 to \$6.96 per Mcf for the fourth quarter of 2008 and \$4.21 for the first six months of 2009. Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders. 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 income and operating result losses, on a non-cash basis.

## 2009 Highlights and Future Considerations

**6.25% Convertible Perpetual Preferred Stock Offering.** In June 2009, we 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 \$334.6 million after underwriters' fees and offering expenses. We used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement.

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 dividends are declared by our board of directors with the first dividend payment September 15, 2009. 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 our 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 us. At any time on or after June 15, 2013, we may cause all outstanding shares of convertible preferred stock to be automatically converted into shares of common stock if certain conditions are met. 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.

**Sanish Field Transaction.** On June 4, 2009, we 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 has agreed to pay 65% of our net working interest drilling and well completion costs to receive 50% of our working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, we will remain the operator for each unit.

As of June 4, 2009, there were 18 wells drilled or in the process of being drilled on the 26 units covered by the agreement and 12 more wells planned in 2009 on these units. At the closing of the agreement, the private company paid us \$107.3 million, representing \$6.4 million for acreage costs, \$65.8 million for 65% of our cost in the 18 wells drilled or drilling and \$35.1 million for a 50% interest in our Robinson Lake gas plant and oil and gas gathering system. We used the proceeds to repay a portion of the debt outstanding under our credit agreement. We sold estimated proved reserves of 2.8 MMBOE, as of June 1, 2009, as a result of this transaction.

**Common Stock Offering.** In February 2009, we completed a public offering of our 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. We used the net offering proceeds to repay a portion of the debt outstanding under

Whiting Oil and Gas' credit agreement, and we plan to use the increased credit availability to fund a portion of the planned capital expenditures in our 2009 capital budget.

23

---

Table of Contents

Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken formation. Net production in the Sanish field increased 200% from a net 3.4 MBOE/d in June 2008 to a net 10.2 MBOE/d in June 2009. Net production in the Parshall field increased 6% from a net 5.0 MBOE/d in June 2008 to a net 5.3 MBOE/d in June 2009.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve and production increases. Our expansion of the CO2 flood at both fields continues to generate positive results. During the first half of 2009, we incurred \$98.5 million of development expenditures on these two projects.

The Postle field is located in Texas County, Oklahoma. Four of our five producing units are currently under active CO2 enhanced recovery projects. As of July 17, 2009, we were injecting 130 MMcf/d of CO2 in this field. Production from the field has increased 39% from a net 6.3 MBOE/d in June 2008 to a net 8.7 MBOE/d in June 2009. Operations are under way to expand CO2 injection into the northern part of the fourth unit, HMU, and to optimize flood patterns in the existing CO2 floods. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells.

The North Ward Estes field is located in Ward and Winkler Counties, Texas and is responding positively to our water and CO2 floods, which we initiated in Phase I during May 2007. In early March 2009, we began CO2 injection in Phase II of the project. As of July 17, 2009, we were injecting 144 MMcf/d of CO2 in this field. Production from the field has increased 22% from a net 5.4 MBOE/d in June 2008 to a net 6.5 MBOE/d in June 2009. 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 four phases through 2015, and we estimate that the first three phases will be substantially complete by December 2009.

Table of Contents

## Results of Operations

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Selected Operating Data:	Six Months Ended June 30,	
	2009	2008
Net production:		
Oil (MMBbls)	7.3	5.4
Natural gas (Bcf)	15.5	14.2
Total production (MMBOE)	9.9	7.8
Net sales (in millions):		
Oil (1)	\$ 307.3	\$ 549.4
Natural gas (1)	53.2	127.9
Total oil and natural gas sales	\$ 360.5	\$ 677.3
Average sales prices:		
Oil (per Bbl)	\$ 41.85	\$ 101.88
Effect of oil hedges on average price (per Bbl)	1.40	(13.17)
Oil net of hedging (per Bbl)	\$ 43.25	\$ 88.71
Average NYMEX price	\$ 51.46	\$ 110.98
Natural gas (per Mcf)	\$ 3.44	\$ 8.99
Effect of natural gas hedges on average price (per Mcf)	0.04	-
Natural gas net of hedging (per Mcf)	\$ 3.48	\$ 8.99
Average NYMEX price	\$ 4.21	\$ 9.49
Cost and expense (per BOE):		
Lease operating expenses	\$ 11.95	\$ 14.58
Production taxes	\$ 2.46	\$ 5.63
Depreciation, depletion and amortization expense	\$ 20.19	\$ 13.56
General and administrative expenses	\$ 1.94	\$ 4.46

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased \$316.8 million to \$360.5 million in the first half of 2009 compared to the same period in 2008. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 36% between periods, while our natural gas sales volumes increased 9%. 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<sub>2</sub> projects, Postle and North Ward Estes. Oil production from the Bakken area increased 1,775 MBbl compared to the first half of 2008, while Postle oil production increased 295 MBbl and North Ward Estes oil production increased 250 MBbl over the same prior year period. These production increases were partially offset by the Whiting USA Trust I (the "Trust") divestiture, which decreased oil production by 230 MBbl, as well as normal field production decline. The gas volume increase between periods was primarily the result of incremental gas production of 1,795 MMcf from the Flat Rock acquisition, which we completed on May 30, 2008, and higher production due to well completions in the Boies Ranch area of 1,315 MMcf, in the Gulf Coast region of 995 MMcf and in the North Dakota Bakken area of 585 MMcf. These production increases were partially offset by the Trust divestiture, which decreased gas production by 1,155 MMcf, as well as normal field production decline. Offsetting the production increases were decreases in average sales prices. Our average price for oil before

effects of hedging decreased 59% between periods, and our average price for natural gas before effects of hedging decreased 62%.

25

---

Table of Contents

Gain (Loss) on Oil Hedging Activities. Realized cash settlements on commodity derivatives that we have designated as cash flow hedges are recognized as gain (loss) on oil hedging activities. During the first half of 2009, we incurred cash settlement gains of \$13.5 million on such crude oil hedges. During the first half of 2008, we incurred realized cash settlement losses of \$71.0 million on crude oil derivatives designated as cash flow hedges. None of our natural gas derivatives were designated as cash flow hedges during the first six months of 2009 or 2008. Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. As a result, we reclassified from accumulated other comprehensive income into earnings \$6.8 million in unrealized noncash gains upon the expiration of these de-designated crude oil hedges during the second quarter of 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 7, 2009.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public and related oil and gas property conveyance on April 30, 2008, we recognized a deferred gain on sale of \$100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the six months ended June 30, 2009 and 2008, we recognized \$8.4 million and \$3.0 million, respectively, in income as amortization of deferred gain on sale.

Gain on Sale of Properties. 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. There was no gain or loss on the sale of properties during the six months ended June 30, 2008.

Lease Operating Expenses. Our lease operating expenses during the first half of 2009 were \$118.5 million, a \$5.4 million or 5% increase over the same period in 2008. Our lease operating expenses per BOE, however, decreased from \$14.58 during the first half of 2008 to \$11.95 during the first half of 2009. The decrease of 18% on a BOE basis was primarily caused by increased production and a decrease of \$6.3 million in electric power and fuel costs during the first half of 2009 as compared to the first half of 2008, partially offset by a high level of workover activity. Workovers amounted to \$26.3 million in the first half of 2009, as compared to \$8.4 million in the first half of 2008. The increase in workover activity primarily relates to our two CO<sub>2</sub> projects, which are evolving past the construction and start-up phases and moving into an ongoing maintenance and repair phase that involves a significantly higher number of producing and injection wells.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the first half of 2009 and 2008 were 6.8% and 6.5%, respectively, of oil and natural gas sales. Our production tax rate for the first half of 2009 was greater than the rate for same period in 2008 mainly due to successful wells completed in the North Dakota Bakken area during the latter half of 2008, which carry an 11.5% production tax rate.

Table of Contents

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased \$95.0 million as compared to the first half of 2008. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30,	
	2009	2008
Depletion	\$ 194,993	\$ 102,251
Depreciation	1,599	1,594
Accretion of asset retirement obligations	3,757	1,477
Total	\$ 200,349	\$ 105,322

DD&A increased \$95.0 million primarily due to \$92.7 million in higher depletion expense between periods. Of this \$92.7 million increase in depletion, \$28.4 million related to higher oil and gas volumes produced during the first half of 2009, while \$64.3 million related to our higher depletion rate in 2009. On a BOE basis, our DD&A rate increased by 49% from \$13.56 for the first half of 2008 to \$20.19 for the first half of 2009. The primary factors causing this rate increase were (i) \$787.3 million in drilling expenditures incurred during the past twelve months, (ii) net oil and natural gas reserve reductions of 11.6 MMBOE during 2008, which were primarily attributable to a 39.0 MMBOE downward revision for lower oil and natural gas prices at December 31, 2008, and (iii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs increased \$7.5 million, as compared to the first half of 2008. The components of exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30,	
	2009	2008
Exploration	\$ 18,811	\$ 14,227
Impairment	8,295	5,400
Total	\$ 27,106	\$ 19,627

Exploration costs increased \$4.6 million during the first half of 2009 as compared to the same period in 2008 primarily due to rig termination fees recognized in the first quarter of 2009, partially offset by decreased accrued Production Participation Plan payments for geological and geophysical (“G&G”) personnel. Rig termination fees totaled \$7.5 million during the first half of 2009, while we did not pay any rig termination fees in the first half of 2008. Accrued Production Participation Plan distributions for exploration personnel were \$2.5 million lower during the first half of 2009 as compared to the same prior year period. The impairment charges in the first half of 2009 and 2008 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of June 30, 2009, the amount of unproved properties being amortized totaled \$81.6 million, as compared to \$72.8 million as of June 30, 2008.



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):

	Six Months Ended June 30,	
	2009	2008
General and administrative expenses	\$ 43,683	\$ 54,314
Reimbursements and allocations	(24,421)	(19,692)
General and administrative expense, net	\$ 19,262	\$ 34,622

General and administrative expense before reimbursements and allocations decreased \$10.6 million to \$43.7 million during the first half of 2009. The largest component of the decrease related to \$17.3 million in lower accrued distributions under our Production Participation Plan ("Plan") between periods due to a lower level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from lower oil and natural gas prices during the first half of 2009 as compared to the same period of 2008, as well as the Trust divestiture completed in April 2008. These lower accrued Plan distributions were partially offset by \$3.6 million in additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2009 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 5% for the first half of 2009 and 2008.

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

	Six Months Ended June 30,	
	2009	2008
Senior Subordinated Notes	\$ 21,745	\$ 21,943
Credit Agreement	8,153	7,652
Amortization of debt issue costs and debt discount	4,355	2,423
Other	933	733
Capitalized interest	(1,813)	(1,534)
Total interest expense	\$ 33,373	\$ 31,217

The increase in interest expense of \$2.2 million between periods was mainly due to increased amortization of \$23.1 million in additional debt issue costs, which were incurred in April 2009 in connection with renewing our credit agreement. Our weighted average effective cash interest rate was 5.0% during the first half of 2009 compared to 6.4% during the first half of 2008. Our weighted average debt outstanding during the first half of 2009 was \$1,210.9 million versus \$929.2 million for the first half of 2008. After inclusion of non-cash interest costs for the amortization of debt issue costs, debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 5.7% during the first half of 2009 compared to 6.9% during the first half of 2008.

Change in Production Participation Plan Liability. For the six months ended June 30, 2009, this non-cash expense was \$3.7 million, a decrease of \$14.2 million as compared to the same period in 2008. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2010 under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2009 and 2008 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during the first half of each respective year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. The average NYMEX prices used to estimate this liability decreased by \$0.81 for crude oil and \$0.43 for natural gas for the six months ended June 30, 2009, as

compared to increases of \$15.51 for crude oil and \$0.74 for natural gas over the same period in 2008. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

Table of Contents

Loss on Mark-to-Market Derivatives. During 2008, we entered into certain 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 (gain) loss on mark-to-market derivatives. The components of our loss on mark-to-market derivatives were as follows (in thousands):

	Six Months Ended June 30,	
	2009	2008
Unrealized mark-to-market derivative losses	\$ 156,973	\$ 17,625
Realized cash settlement losses	2,458	-
Loss on hedging ineffectiveness	22,866	-
Total loss on mark-to-market derivatives	\$ 182,297	\$ 17,625

The increase of \$139.3 million in unrealized mark-to-market derivative losses during the first half of 2009 as compared to the same prior year period was due to the fact that (i) we averaged 21.3 MMBbls of crude oil hedged during the six months ended June 30, 2009, while we only averaged 3.3 MMBbls of crude oil hedged during the six months ended June 30, 2008, and (ii) there was a significant upward shift in the forward price curve for NYMEX crude oil during the six months ended June 30, 2009.

Income Tax Expense (Benefit). Income tax benefit totaled \$78.1 million for the first half of 2009, versus \$83.9 million of income tax expense for the first half of 2008. Our effective income tax rate decreased from 37.0% for the first half of 2008 to 36.3% for the first half of 2009.

Net Income (Loss). Net income (loss) decreased from \$142.8 million in income during the first half of 2008 to a \$136.9 million loss during the first half of 2009. The primary reasons for this decrease include a 51% decrease in oil prices (net of hedging); a 61% decrease in natural gas prices (net of hedging); higher losses on mark-to-market derivatives, lease operating expenses, DD&A, exploration and impairment and interest expense. These negative factors were partially offset by a 28% increase in equivalent volumes sold; lower production taxes, general and administrative expenses, Production Participation Plan expense and income taxes; and higher amortization of deferred gain on sale as well as the gain on sale of properties during the first half of 2009.

Table of Contents

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008

Selected Operating Data:	Three Months Ended June 30,	
	2009	2008
Net production:		
Oil (MMBbls)	3.8	2.8
Natural gas (Bcf)	7.6	7.3
Total production (MMBOE)	5.0	4.0
Net sales (in millions):		
Oil (1)	\$ 191.0	\$ 316.9
Natural gas (1)	23.3	73.6
Total oil and natural gas sales	\$ 214.3	\$ 390.5
Average sales prices:		
Oil (per Bbl)	\$ 50.66	\$ 113.28
Effect of oil hedges on average price (per Bbl)	(1.15)	(17.19)
Oil net of hedging (per Bbl)	\$ 49.51	\$ 96.09
Average NYMEX price	\$ 59.62	\$ 124.00
Natural gas (per Mcf)	\$ 3.08	\$ 10.02
Effect of natural gas hedges on average price (per Mcf)	0.05	-
Natural gas net of hedging (per Mcf)	\$ 3.13	\$ 10.02
Average NYMEX price	\$ 3.50	\$ 10.94
Cost and expense (per BOE):		
Lease operating expenses	\$ 11.44	\$ 14.29
Production taxes	\$ 2.96	\$ 6.48
Depreciation, depletion and amortization expense	\$ 19.93	\$ 13.63
General and administrative expenses	\$ 2.04	\$ 5.72

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased \$176.2 million to \$214.3 million in the second quarter of 2009 compared to the second quarter of 2008. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 35% between periods, while our natural gas sales volumes increased 3%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 785 MBbl compared to the second quarter of 2008, while Postle oil production increased 165 MBbl and North Ward Estes oil production increased 125 MBbl over the same prior year period. These production increases were partially offset by the Whiting USA Trust I (the "Trust") divestiture, which decreased oil production by 55 MBbl, as well as normal field production decline. The gas volume increase between periods was primarily the result of incremental gas production of 610 MMcf from the Flat Rock acquisition, which we completed on May 30, 2008, and higher production due to well completions in the Boies Ranch area of 435 MMcf, in the Gulf Coast region of 345 MMcf, and in the North Dakota Bakken area of 325 MMcf. These production increases were partially offset by the Trust divestiture, which decreased gas production by 260 MMcf, as well as normal field production decline. Offsetting the production increases were lower average sales prices. Our average price for oil before effects of hedging decreased 55% between periods, and our average price for natural gas before effects of hedging decreased 69%.



Table of Contents

**Gain (Loss) on Oil Hedging Activities.** Realized cash settlements on commodity derivatives that we have designated as cash flow hedges are recognized as gain (loss) on oil 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 accumulated other comprehensive income into earnings \$6.8 million in unrealized noncash gains upon the expiration of these de-designated crude oil hedges during the second quarter of 2009. None of our oil derivatives were designated as cash flow hedges during the second quarter of 2009. During the second quarter of 2008, we incurred realized cash settlement losses of \$48.1 million on crude oil derivatives designated as cash flow hedges. None of our natural gas derivatives were designated as cash flow hedges during the second quarter of 2009 or 2008. See Item 3, “Qualitative and Quantitative Disclosures About Market Risk” for a list of our outstanding oil and natural gas derivatives as of July 7, 2009.

**Amortization of Deferred Gain on Sale.** In connection with the sale of 11,677,500 Trust units to the public and related oil and gas property conveyance on April 30, 2008, we recognized a deferred gain on sale of \$100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the three months ended June 30, 2009 and 2008, we recognized \$4.3 million and \$3.0 million, respectively, in income as amortization of deferred gain on sale.

**Gain on Sale of Properties.** 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. There was no gain or loss on the sale of properties during the three months ended June 30, 2008.

**Lease Operating Expenses.** Our lease operating expenses during the second quarter of 2009 were \$57.6 million, a \$0.1 million increase over the same period in 2008. Our lease operating expenses per BOE, however, decreased from \$14.29 during the second quarter of 2008 to \$11.44 during the second quarter of 2009. The decrease of 20% on a BOE basis was primarily caused by increased production and decreased electric power and fuel costs of \$5.7 million during the second quarter of 2009 as compared to the same period in 2008, partially offset by a high level of workover activity. Workovers amounted to \$12.2 million in the second quarter of 2009, as compared to \$4.5 million in the second quarter of 2008. The increase in workover activity primarily relates 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.

**Production Taxes.** The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the second quarter of 2009 and 2008 were 7.0% and 6.7%, respectively, of oil and natural gas sales. Our production tax rate for the second quarter of 2009 was greater than the rate for same period in 2008 mainly due to successful wells completed in the North Dakota Bakken area during the latter half of 2008, which carry an 11.5% production tax rate.

**Depreciation, Depletion and Amortization.** Our depreciation, depletion and amortization (“DD&A”) expense increased \$45.5 million as compared to the second quarter of 2008. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30,	
	2009	2008
Depletion	\$ 97,989	\$ 53,207
Depreciation	767	843

Accretion of asset retirement obligations		1,559		761
Total	\$	100,315	\$	54,811

31

---

Table of Contents

DD&A increased \$45.5 million primarily due to \$44.8 million in higher depletion expense between periods. Of this \$44.8 million increase in depletion, \$13.4 million related to higher oil and gas volumes produced during the second quarter of 2009, while \$31.4 million related to our higher depletion rate in 2009. On a BOE basis, our DD&A rate increased by 46% from \$13.63 for the second quarter of 2008 to \$19.93 for the second quarter of 2009. The primary factors causing this rate increase were (i) \$787.3 million in drilling expenditures incurred during the past twelve months, (ii) net oil and natural gas reserve reductions of 11.6 MMBOE during 2008, which were primarily attributable to a 39.0 MMBOE downward revision for lower oil and natural gas prices at December 31, 2008, and (iii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs increased \$1.1 million, as compared to the second quarter of 2008. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended June 30,	
	2009	2008
Exploration	\$ 6,178	\$ 5,815
Impairment	3,614	2,828
Total	\$ 9,792	\$ 8,643

Exploration costs increased \$0.4 million during the second quarter of 2009 as compared to the same period in 2008 primarily due to rig termination fees recognized in the second quarter of 2009 and increased G&G activity, partially offset by a decrease in accrued Production Participation Plan payments for exploration personnel. Rig termination fees totaled \$1.3 million during the second quarter of 2009, while we did not pay any rig termination fees in the second quarter of 2008. G&G costs increased as a result of \$1.3 million in additional seismic related costs incurred during the second quarter of 2009, as compared to the second quarter of 2008. Accrued Production Participation Plan distributions for exploration personnel were \$0.6 million lower during the second quarter of 2009 as compared to the same prior year period. The impairment charges in the second quarter of 2009 and 2008 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of June 30, 2009, the amount of unproved properties being amortized totaled \$81.6 million, as compared to \$72.8 million as of June 30, 2008.



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,	
	2009	2008
General and administrative expenses	\$ 22,687	\$ 33,203
Reimbursements and allocations	(12,405)	(10,196)
General and administrative expense, net	\$ 10,282	\$ 23,007

General and administrative expense before reimbursements and allocations decreased \$10.5 million to \$22.7 million during the second quarter of 2009. The largest component of the decrease related to \$13.1 million in lower accrued distributions under our Production Participation Plan ("Plan") between periods due to a lower level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from lower oil and natural gas prices during the second quarter of 2009 as compared to the same period of 2008, as well as the Trust divestiture completed in April 2008. These lower accrued Plan distributions were partially offset by \$1.0 million in additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2009 was 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 6% for the second quarter of 2008 to 5% for the second quarter of 2009.

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

	Three Months Ended June 30,	
	2009	2008
Senior Subordinated Notes	\$ 10,977	\$ 10,863
Credit Agreement	4,940	3,735
Amortization of debt issue costs and debt discount	3,183	1,206
Other	482	379
Capitalized interest	(889)	(512)
Total interest expense	\$ 18,693	\$ 15,671

The increase in interest expense of \$3.0 million between periods was mainly due to a higher level of debt outstanding under our credit agreement and increased amortization of incremental debt issue costs that were added during the second quarter of 2009, partially offset by lower interest rates on borrowings under our credit agreement during the second quarter of 2009. As a result of our renewing our credit agreement, we incurred debt issue costs of \$23.1 million. Our weighted average effective cash interest rate was 5.6% during the second quarter of 2009 compared to 6.1% during the second quarter of 2008. Our weighted average debt outstanding during the second quarter of 2009 was \$1,206.0 million versus \$956.7 million for the second quarter of 2008. After inclusion of non-cash interest costs for the amortization of debt issue costs, debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 6.7% during the second quarter of 2009 compared to 6.6% during the second quarter of 2008.

Table of Contents

**Change in Production Participation Plan Liability.** For the three months ended June 30, 2009, this non-cash expense was \$3.3 million, a decrease of \$8.4 million as compared to the same period in 2008. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2010 under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2009 and 2008 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during the second quarter of each respective year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. The average NYMEX prices used to estimate this liability increased by \$0.01 for crude oil and decreased by \$0.21 for natural gas for the three months ended June 30, 2009, as compared to increases of \$12.28 for crude oil and \$0.55 for natural gas over the same period in 2008. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

**Loss on Mark-to-Market Derivatives.** During 2008, we entered into certain 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 (gain) loss on mark-to-market derivatives. The components of our loss on mark-to-market derivatives were as follows (in thousands):

	Three Months Ended June 30,	
	2009	2008
Unrealized mark-to-market derivative losses	\$ 156,544	\$ 20,562
Realized cash settlement losses	3,988	-
Total loss on mark-to-market derivatives	\$ 160,532	\$ 20,562

The increase of \$136.0 million in unrealized mark-to-market derivative losses during the second quarter of 2009 as compared to the same prior year period was due to the fact that (i) we averaged 20.4 MMBbls of crude oil hedged during the three months ended June 30, 2009, while we only averaged 3.1 MMBbls of crude oil hedged during the three months June 30, 2008, and (ii) there was a significant upward shift in the forward price curve for NYMEX crude oil during the three months ended June 30, 2009.

**Income Tax Expense (Benefit).** Income tax benefit totaled \$52.1 million for the second quarter of 2009, versus \$47.4 million of income tax expense for the second quarter of 2008. Our effective income tax rate decreased from 37.1% for the second quarter of 2008 to 35.9% for the second quarter of 2009.

**Net Income (Loss).** Net income (loss) decreased from \$80.4 million in income during the second quarter of 2008 to a \$93.2 million loss during the second quarter of 2009. The primary reasons for this decrease include a 48% decrease in oil prices (net of hedging); a 69% decrease in natural gas prices (net of hedging); higher losses on mark-to-market derivatives, lease operating expenses, DD&A, exploration and impairment and interest expense. These negative factors were partially offset by a 25% increase in equivalent volumes sold; lower production taxes, general and administrative expenses, Production Participation Plan expense and income taxes; and higher amortization of deferred gain on sale as well as the gain on sale of properties during the second quarter of 2009.

Table of Contents

## Liquidity and Capital Resources

Overview. At June 30, 2009, our debt to total capitalization ratio was 27.1%, we had \$13.2 million of cash on hand and \$2,257.3 million of stockholders' equity. At December 31, 2008, our debt to total capitalization ratio was 40.7%, we had \$9.6 million of cash on hand and \$1,808.8 million of stockholders' equity. In the first half of 2009, we generated \$144.3 million of cash provided by operating activities, a decrease of \$184.8 million over the same period in 2008. Cash provided by operating activities decreased primarily due to lower average sales prices for both crude oil and natural gas, partially offset by higher oil and gas volumes produced in the first half of 2009. We also generated \$146.2 million from financing activities consisting of \$334.6 million in net proceeds received from the issuance of our preferred stock and \$234.8 million in net proceeds received from the issuance of our common stock, partially offset by net repayments under our credit agreement totaling \$400.0 million. Cash flows from operating and financing activities, as well as \$79.6 million in net proceeds from the sale of interests in certain properties in the Sanish field, were used to finance \$327.8 million of drilling and development expenditures paid in the first half of 2009 and \$38.7 million of cash acquisition capital expenditures. The following chart details our exploration and development expenditures incurred by region during the first half of 2009 (in thousands):

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	\$ 152,032	\$ 9,652	\$ 161,684	57%
Permian Basin	87,551	5,604	93,155	33%
Mid-Continent	23,782	522	24,304	9%
Gulf Coast	1,069	3,028	4,097	1%
Michigan	908	5	913	0%
Total incurred	265,342	18,811	284,153	100%
Decrease in accrued capital expenditures	62,498	-	62,498	
Total paid	\$ 327,840	\$ 18,811	\$ 346,651	

We continually evaluate our capital needs and compare them to our capital resources. Our current 2009 capital budget for exploration and development expenditures is \$440.0 million, which we expect to fund with net cash provided by our operating activities and a portion of the proceeds from the common stock offering we completed in February 2009. Our 2009 capital budget of \$440.0 million, however, represents a significant decrease from the \$947.4 million incurred on exploration and development expenditures during 2008. This reduced capital budget is in response to significantly lower oil and natural gas prices experienced during the fourth quarter of 2008 and continuing into 2009. Although we have no specific budget for property acquisitions in 2009, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed \$440.0 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.

Credit Agreement. As of June 30, 2009, Whiting Oil and Gas Corporation, ("Whiting Oil and Gas"), our wholly-owned subsidiary, had a credit agreement with a syndicate of banks that had a borrowing base of \$1.1 billion with \$877.2 million of available borrowing capacity, which is net of \$220.0 million in borrowings and \$2.8 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2012, when the entire amount

is due.

35

---

Table of Contents

The borrowing base under the renewed 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, 2009, \$47.2 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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 4.5 to 1.0 for quarters ending prior to and on September 30, 2010, 4.25 to 1.0 for quarters ending December 31, 2010 to June 30, 2011 and 4.0 to 1.0 for quarters ending September 30, 2011 and thereafter, (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement 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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and 2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. Except for limited exceptions, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, the credit agreement restricts our ability to make any dividends 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, 2009.

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, 2009. However, a substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Table of Contents

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liabilities since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of June 30, 2009 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

Contractual Obligations	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a)	\$ 840,000	\$ -	\$ 370,000	\$ 470,000	\$ -
Cash interest expense on debt (b)	186,608	49,429	96,179	41,000	-
Asset retirement obligation (c)	70,944	10,046	2,996	8,999	48,903
Tax sharing liability (d)	24,505	2,112	3,787	3,261	15,345
Derivative fair value liability (e)	132,256	34,362	59,585	38,309	-
Purchasing obligations (f)	158,366	34,539	72,878	46,570	4,379
Drilling rig contracts (g)	102,958	45,524	50,174	7,260	-
Operating leases (h)	12,636	2,531	6,310	3,795	-
<b>Total</b>	<b>\$ 1,528,273</b>	<b>\$ 178,543</b>	<b>\$ 661,909</b>	<b>\$ 619,194</b>	<b>\$ 68,627</b>

- (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 due April 2012, 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 2.3%.
- (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, 2009 consists of a \$16.9 million payable to Whiting USA Trust I (“Trust”) for derivative contracts that we have entered into but have in turn conveyed to the Trust. Although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to the Trust under the terms of the conveyance. The above derivative obligation at June 30, 2009 also consists of a \$115.4 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil and natural gas price fluctuations. With respect to our open derivative contracts at June 30, 2009 with certain counterparties, the forward price curves for crude oil and natural gas generally exceeded the price curves that were in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar’s price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market and commodity price risk.
- (f) We have two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby we have committed to buy certain volumes of CO<sub>2</sub>, 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 CO<sub>2</sub> (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 CO<sub>2</sub> volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.
- (g) We currently have six drilling rigs under long-term contract, of which one drilling rig expires in 2009, two in 2010, one in 2011, one in 2012 and one in 2013. All of these rigs are operating in the Rocky Mountains region. Included in the above obligation is \$3.0 million of rig termination fees that we accrued as a current payable at June 30, 2009 for the cancellation of long-term contracts on one drilling rig. As of June 30, 2009, early termination of the remaining contracts would require additional termination penalties of \$63.7 million, which would be in lieu of paying the remaining drilling commitments of \$100.0 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the drilling time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.
- (h) We lease 107,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, and an additional 46,700 square feet of office space in Midland, Texas expiring in 2012.

## 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, 2008.

### Effects of Inflation and Pricing

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

### Forward-Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe” or “show” 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 financial crisis; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain CO<sub>2</sub>; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; risks related to our level of indebtedness and periodic redeterminations of Whiting Oil and Gas Corporation's borrowing base under our credit agreement; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions; 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 this Quarterly Report on Form 10-Q. 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, 2008 and have not materially changed since that report was filed.

Our outstanding hedges as of July 7, 2009 are summarized below:

## Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	07/2009 to 09/2009	496,000	\$ 57.12/\$ 69.55
Crude Oil	10/2009 to 12/2009	478,000	\$ 61.04/\$ 74.89
Crude Oil	01/2010 to 03/2010	430,000	\$ 60.27/\$ 74.81
Crude Oil	04/2010 to 06/2010	415,000	\$ 62.69/\$ 80.09
Crude Oil	07/2010 to 09/2010	405,000	\$ 60.28/\$ 76.98
Crude Oil	10/2010 to 12/2010	390,000	\$ 60.29/\$ 78.23
Crude Oil	01/2011 to 03/2011	360,000	\$ 56.25/\$ 83.78
Crude Oil	04/2011 to 06/2011	360,000	\$ 56.25/\$ 83.78
Crude Oil	07/2011 to 09/2011	360,000	\$ 56.25/\$ 83.78
Crude Oil	10/2011 to 12/2011	360,000	\$ 56.25/\$ 83.78
Crude Oil	01/2012 to 03/2012	330,000	\$ 55.91/\$ 85.46
Crude Oil	04/2012 to 06/2012	330,000	\$ 55.91/\$ 85.46
Crude Oil	07/2012 to 09/2012	330,000	\$ 55.91/\$ 85.46
Crude Oil	10/2012 to 12/2012	330,000	\$ 55.91/\$ 85.46
Crude Oil	01/2013 to 03/2013	290,000	\$ 55.34/\$ 85.94
Crude Oil	04/2013 to 06/2013	290,000	\$ 55.34/\$ 85.94
Crude Oil	07/2013 to 09/2013	290,000	\$ 55.34/\$ 85.94
Crude Oil	10/2013	290,000	\$ 55.34/\$ 85.94
Crude Oil	11/2013	190,000	\$ 54.59/\$ 81.78

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (as further explained above in the note on Acquisitions and Divestitures), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 1,713 MBbls of crude oil and 6,573 MMcf of natural gas from 2009 through 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

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

Table of Contents

## Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	07/2009 to 09/2009	47,510	\$ 76.00/\$ 136.41
Crude Oil	10/2009 to 12/2009	46,240	\$ 76.00/\$ 135.72
Crude Oil	01/2010 to 03/2010	45,084	\$ 76.00/\$ 135.09
Crude Oil	04/2010 to 06/2010	43,978	\$ 76.00/\$ 134.85
Crude Oil	07/2010 to 09/2010	42,966	\$ 76.00/\$ 134.89
Crude Oil	10/2010 to 12/2010	41,924	\$ 76.00/\$ 135.11
Crude Oil	01/2011 to 03/2011	40,978	\$ 74.00/\$ 139.68
Crude Oil	04/2011 to 06/2011	40,066	\$ 74.00/\$ 140.08
Crude Oil	07/2011 to 09/2011	39,170	\$ 74.00/\$ 140.15
Crude Oil	10/2011 to 12/2011	38,242	\$ 74.00/\$ 140.75
Crude Oil	01/2012 to 03/2012	37,412	\$ 74.00/\$ 141.27
Crude Oil	04/2012 to 06/2012	36,572	\$ 74.00/\$ 141.73
Crude Oil	07/2012 to 09/2012	35,742	\$ 74.00/\$ 141.70
Crude Oil	10/2012 to 12/2012	35,028	\$ 74.00/\$ 142.21
Natural Gas	07/2009 to 09/2009	192,870	\$ 6.00/\$ 15.60
Natural Gas	10/2009 to 12/2009	185,430	\$ 7.00/\$ 14.85
Natural Gas	01/2010 to 03/2010	178,903	\$ 7.00/\$ 18.65
Natural Gas	04/2010 to 06/2010	172,873	\$ 6.00/\$ 13.20
Natural Gas	07/2010 to 09/2010	167,583	\$ 6.00/\$ 14.00
Natural Gas	10/2010 to 12/2010	162,997	\$ 7.00/\$ 14.20
Natural Gas	01/2011 to 03/2011	157,600	\$ 7.00/\$ 17.40
Natural Gas	04/2011 to 06/2011	152,703	\$ 6.00/\$ 13.05
Natural Gas	07/2011 to 09/2011	148,163	\$ 6.00/\$ 13.65
Natural Gas	10/2011 to 12/2011	142,787	\$ 7.00/\$ 14.25
Natural Gas	01/2012 to 03/2012	137,940	\$ 7.00/\$ 15.55
Natural Gas	04/2012 to 06/2012	134,203	\$ 6.00/\$ 13.60
Natural Gas	07/2012 to 09/2012	130,173	\$ 6.00/\$ 14.45
Natural Gas	10/2012 to 12/2012	126,613	\$ 7.00/\$ 13.40

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil contracts listed in both tables above, a hypothetical \$5.00 change in the NYMEX forward curve as of June 30, 2009 applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives of \$66.2 million. For the natural gas contracts listed above, a hypothetical \$0.50 change in the NYMEX forward curve as of June 30, 2009 applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives of \$0.4 million.

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

Commodity	Remaining Period	Monthly Volume (MMBtu)	2009 Price Per MMBtu
-----------	---------------------	---------------------------	-------------------------

Edgar Filing: WHITING PETROLEUM CORP - Form 10-Q

Natural Gas	07/2009 to 05/2011	23,000	\$ 5.14
Natural Gas	07/2009 to 09/2012	67,000	\$ 4.56

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, 2009. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of June 30, 2009 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2009 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. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2008, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of low oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the level of global oil and gas exploration and production activity;
  - the level of global oil and gas inventories;
  - weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and gas in captive market areas; and
  - the price and availability of alternative fuels.

Furthermore, the recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets has led to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy and resulted in lower oil and natural gas prices. Oil and natural gas prices have fallen significantly since their third quarter 2008 levels. For example, the daily average NYMEX oil price was \$118.13 per Bbl for the third quarter of 2008, \$58.75 per Bbl for the fourth quarter of 2008, and \$51.46 per Bbl for the first six months of 2009. Similarly, daily average NYMEX natural gas prices have declined from \$10.27 per Mcf for the third quarter of 2008 to \$6.96 per Mcf for the fourth quarter of 2008 and \$4.21 for the first six months of 2009.

Table of Contents

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may 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, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil and natural 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, 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.

The global financial crisis and recession may have impacts on our business and financial condition that we currently cannot predict.

The continued turmoil in the global financial system and the current global recession may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our development, exploitation, production and exploration activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read “— Reserve estimates depend on many assumptions that may turn out to be inaccurate . . .” later in these Risk Factors for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
  - pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and CO<sub>2</sub>;
  - equipment failures or accidents;



Table of Contents

- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil and natural gas prices; and
- title problems.

Prospects that we decide to drill may not yield oil or gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 and our Annual Report on Form 10-K for the year ended December 31, 2008. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flowrates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2008, we had identified a drilling inventory of over 1,400 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during the fourth quarter of 2008, we recorded a \$10.9 million non-cash charge for the partial impairment of unproved properties in the central Utah Hingeline play. We may also incur such impairment charges in the future, which could

have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. Out of a total of 892,130 gross (420,776 net) undeveloped acreage as of December 31, 2008, the portion that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 17% in 2009, 16% in 2010, and 16% in 2011.

45

---

Table of Contents

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO<sub>2</sub> into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO<sub>2</sub> as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO<sub>2</sub>. Under our CO<sub>2</sub> contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO<sub>2</sub> to us and other parties with whom it has CO<sub>2</sub> contracts, then the supplier may reduce the amount of CO<sub>2</sub> on a pro rata basis it provides to us and such other parties. If this occurs, we may not have sufficient CO<sub>2</sub> to produce oil and natural gas in the manner or to the extent that we anticipate. These contracts are also structured as “take-or-pay” arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO<sub>2</sub> as part of our enhanced recovery techniques.

The development of the proved undeveloped reserves in the North Ward Estes and Postle fields may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2008, undeveloped reserves comprised 46.5% of the North Ward Estes field’s total estimated proved reserves and 16.8% of the Postle field’s total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of \$410.1 million at the North Ward Estes field and \$84.5 million at the Postle field as of December 31, 2008. Together, these fields encompass 58% of our total estimated future development costs of \$857.1 million related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO<sub>2</sub> injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we review periodically the carrying value of our oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, which may include depressed oil and natural gas prices, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to our Annual Report on Form 10-K for the year ended December 31, 2008.

Table of Contents

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in our Annual Report on Form 10-K for the year ended December 31, 2008. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in our the Annual Report on Form 10-K for the year ended December 31, 2008, is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If natural gas prices decline by \$0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2008 would have decreased from \$1,376.4 million to \$1,366.0 million. If oil prices decline by \$1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2008 would have decreased from \$1,376.4 million to \$1,326.1 million.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of June 30, 2009, we had \$220.0 million in borrowings and \$2.8 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit agreement with \$877.2 million of available borrowing capacity, as well as \$620.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's credit agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
  - potentially limiting our ability to pay dividends in cash on our convertible perpetual preferred stock;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

Table of Contents

- placing us at a competitive disadvantage relative to other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas Corporation's credit agreement may be at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. In addition, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas Corporation's credit agreement is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our debt under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas Corporation's credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements will limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
  - make loans to others;
  - make investments;
  - incur additional indebtedness or issue preferred stock;
  - create certain liens;
  - sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole;

- engage in transactions with affiliates;
- enter into hedging contracts;

Table of Contents

- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas Corporation's credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 4.5 to 1.0 for quarters ending prior to and on September 30, 2010, 4.25 to 1.0 for quarters ending December 31, 2010 to June 30, 2011 and 4.0 to 1.0 for quarters ending September 30, 2011 and thereafter, (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement) of not less than 1.0 to 1.0 and (iii) to not exceed a senior secured debt to EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and 2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. Also, the indentures under which we issued our senior subordinated 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. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas Corporation's credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds. Furthermore, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of equity and debt issuances, bank borrowings and internally generated cash flows. We intend to finance future capital expenditures with cash flow from operations and existing financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
  - the prices at which oil and natural gas are sold; and
  - our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our bank credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.



Table of Contents

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
  - we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
  - we may issue additional equity or debt securities related to future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program. From 2004 through 2008, we completed 13 separate acquisitions of producing properties with a combined purchase price of \$1,823.8 million for estimated proved reserves as of the effective dates of the acquisitions of 226.9 MMBOE. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;

- timing of future development costs;

Table of Contents

- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of July 7, 2009, we had contracts, which include our 24.2% share of the Whiting USA Trust I hedges, covering the sale for the remainder of 2009 of between 489,190 and 507,497 barrels of oil per month and between 134,874 and 136,675 MMBtu of natural gas per month. All our oil hedges will expire by November 2013, and all our natural gas hedges will expire by December 2012. See “Quantitative and Qualitative Disclosure about Market Risk” in Item 3 of this Form 10-Q for pricing and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions or unwind hedging transaction we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

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 such, subsequent to March 31, 2009 we recognize 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. Subsequently, we may experience significant net income and operating result losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially

increase our operating and capital costs.

51

---

Table of Contents

The differential between the NYMEX or other benchmark price of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount to the relevant benchmark prices such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
  - abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
  - fires and explosions;
- personal injuries and death; and
  - natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Table of Contents

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

Market conditions or operational impediments may hinder our access to oil and gas markets or delay our production.

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
  - drilling bonds;
- reports concerning operations;
  - the spacing of wells;
- unitization and pooling of properties; and

- taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Table of Contents

Our operations may incur substantial liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities, and concentration of materials that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Federal law and some state laws also allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases”, including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere. In response to such studies, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider legislation to regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emission of these gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court’s holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act’s definition of “air pollutant” may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. As a result of the Massachusetts decision, in April 2009, the EPA published a Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under the Clean Air Act. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we operate could adversely affect our operations by increasing costs. The cost increases would result from the potential new requirements to install additional emission control equipment and by increasing our monitoring and record-keeping burden.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.



Table of Contents

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our Chairman, President and Chief Executive Officer; James T. Brown, our Senior Vice President; Rick A. Ross, our Vice President, Operations; Peter W. Hagist, our Vice President, Permian Operations; J. Douglas Lang, our Vice President, Reservoir Engineering/Acquisitions; David M. Seery, our Vice President of Land; Michael J. Stevens, our Vice President and Chief Financial Officer; or Mark R. Williams, our Vice President, Exploration and Development, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis or within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

In May 2009, President Obama's Administration released revenue proposals in "General Explanations of the Administration's Fiscal 2010 Revenue Proposals" that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. In April 2009, the Oil Industry Tax Break Repeal Act of 2009, or the Senate Bill, was introduced in the Senate and includes many of the proposals outlined in the revenue proposals. It is unclear whether any such changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the revenue proposals, the Senate Bill or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively impact our financial condition and results of operations.



Table of Contents

## Item 4. Submission of Matters to a Vote of Security Holders

Whiting Petroleum Corporation held its annual meeting of stockholders on May 5, 2009. At such meeting, James J. Volker, William N. Hahne and Graydon D. Hubbard and were reelected as directors for terms to expire at the 2012 annual meeting of stockholders and until their successors are duly elected and qualified pursuant to the following votes:

Name of Nominee	Shares Voted	
	For	Withheld
James J. Volker	38,586,992	5,329,688
William N. Hahne	39,586,070	4,330,610
Graydon D. Hubbard	39,673,297	4,243,383

The other directors of Whiting Petroleum Corporation whose terms of office continued after the 2009 annual meeting of stockholders are as follows: terms expiring at the 2010 annual meeting: Thomas L. Aller and Thomas P. Briggs; and terms expiring at the 2011 annual meeting: D. Sherwin Artus and Palmer L. Moe.

The following other matter brought for vote at the 2009 annual meeting of stockholders passed by the vote indicated:

	Shares Voted			Broker Non-Vote
	For	Against	Abstain	
Ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm	43,775,164	107,608	33,908	-

## 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, 2009.

WHITING PETROLEUM CORPORATION

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

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

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

Table of Contents

EXHIBIT INDEX

Exhibit

Number	Exhibit Description
(3.1)	Certificate of Designations of 6.25% Convertible Perpetual Preferred Stock of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated June 17, 2009 (File No. 001- 31899)].
(4.1)	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 15, 2009, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents and lenders party thereto [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated June 15, 2009 (File No. 001- 31899)].
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.