WHITING PETROLEUM CORP
Form 10-Q
July 29, 2011

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

FORM 10-Q

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

For the quarterly period ended June 30, 2011
or

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

For the transition period from _______________ to _______________

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

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

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

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

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

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

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

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

Number of shares of the registrant's common stock outstanding at July 15, 2011: 117,380,843 shares.

TABLE OF CONTENTS

Table of Contents

GLOSSARY OF CERTAIN DEFINITIONS

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

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

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

“Bcf” One billion cubic feet of natural gas.

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

“FASB” The Financial Accounting Standards Board.

“FASB ASC” The FASB Accounting Standards Codification.

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

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

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet of natural gas.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet of natural gas.

“MMcf/d” One MMcf 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 and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

1

Table of Contents

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

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

ASSETS	June 30, 2011	December 31, 2010
Current assets:		
Cash and cash equivalents	$ 11,089	$ 18,952
Accounts receivable trade, net	211,937	199,713
Prepaid expenses and other	20,189	14,878
Total current assets	243,215	233,543
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	6,337,627	5,661,619
Unproved properties	319,271	226,336
Other property and equipment	140,428	98,092
Total property and equipment	6,797,326	5,986,047
Less accumulated depreciation, depletion and amortization	(1,845,652)	(1,630,824)
Total property and equipment, net	4,951,674	4,355,223
Debt issuance costs	33,388	34,226
Other long-term assets	58,655	25,785
TOTAL ASSETS	$ 5,286,932	$ 4,648,777
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 77,020	$ 35,016
Accrued capital expenditures	96,005	84,789
Accrued liabilities and other	115,020	153,062
Revenues and royalties payable	100,435	82,124
Taxes payable	31,194	30,291
Derivative liabilities	61,820	69,375
Deferred income taxes	3,135	4,548
Total current liabilities	484,629	459,205
Long-term debt	1,060,000	800,000
Deferred income taxes	662,036	539,071
Derivative liabilities	98,735	95,256
Production Participation Plan liability	83,731	81,524
Asset retirement obligations	80,369	76,994
Deferred gain on sale	35,748	41,460
Other long-term liabilities	25,876	23,952
Total liabilities	2,531,124	2,117,462
Commitments and contingencies		
Equity:		
	-	-

Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,400 shares issued and outstanding as of June 30, 2011 and 172,500 shares issued and outstanding as of December 31, 2010, aggregate liquidation preference of $17,240,000 at June 30, 2011				
Common stock, $0.001 par value, 300,000,000 shares authorized; 118,113,052 issued and 117,380,843 outstanding as of June 30, 2011, 117,967,876 issued and 117,098,506 outstanding as of December 31, 2010 (1)		118		59
Additional paid-in capital		1,547,342		1,549,822
Accumulated other comprehensive income		2,325		5,768
Retained earnings		1,197,690		975,666
Total Whiting shareholders’ equity		2,747,475		2,531,315
Noncontrolling interest		8,333		-
Total equity		2,755,808		2,531,315
TOTAL LIABILITIES AND EQUITY	$	5,286,932	$	4,648,777

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

See notes to consolidated financial statements.

2

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,	
	2011	2010	2011	2010
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 473,865	$ 363,028	$ 899,548	$ 703,722
Gain on hedging activities	2,391	8,525	5,454	15,259
Amortization of deferred gain on sale	3,570	4,022	6,937	7,759
Gain on sale of properties	1,227	1,918	1,227	1,918
Interest income and other	153	134	261	240
Total revenues and other income	481,206	377,627	913,427	728,898
COSTS AND EXPENSES:				
Lease operating	73,785	67,730	145,307	128,585
Production taxes	34,258	26,050	65,902	51,148
Depreciation, depletion and amortization	110,250	94,583	217,978	192,132
Exploration and impairment	20,171	14,509	42,408	27,415
General and administrative	20,913	15,402	39,326	29,036
Interest expense	15,279	15,632	29,737	31,324
Change in Production Participation Plan liability	2,650	4,747	2,207	5,692
Commodity derivative (gain) loss, net	(113,618)	(63,496)	20,820	(78,418)
Total costs and expenses	163,688	175,157	563,685	386,914
INCOME BEFORE INCOME TAXES	317,518	202,470	349,742	341,984
INCOME TAX EXPENSE:				
Current	1,565	5,308	3,615	6,638
Deferred	112,804	71,845	123,564	123,418
Total income tax expense	114,369	77,153	127,179	130,056
NET INCOME	203,149	125,317	222,563	211,928
Preferred stock dividends	(269)	(5,391)	(539)	(10,781)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 202,880	$ 119,926	$ 222,024	$ 201,147

EARNINGS PER COMMON SHARE(1):				
Basic	$ 1.73	$ 1.18	$ 1.89	$ 1.97
Diluted	$ 1.71	$ 1.06	$ 1.87	$ 1.79
WEIGHTED AVERAGE SHARES OUTSTANDING(1) :				
Basic	117,373	101,989	117,308	101,906
Diluted	118,659	118,449	118,707	118,469

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

See notes to consolidated financial statements.

Table of Contents

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 222,563	$ 211,928
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	217,978	192,132
Deferred income tax expense	123,564	123,418
Amortization of debt issuance costs and debt discount	4,241	5,724
Stock-based compensation	6,627	4,390
Amortization of deferred gain on sale	(6,937)	(7,759)
Gain on sale of properties	(1,227)	(1,918)
Undeveloped leasehold and oil and gas property impairments	15,442	7,700
Exploratory dry hole costs	4,297	2,597
Change in Production Participation Plan liability	2,207	5,692
Unrealized (gain) loss on derivative contracts	(8,570)	(105,236)
Other non-current	(4,955)	(2,287)
Changes in current assets and liabilities:		
Accounts receivable trade	(12,224)	(17,027)
Prepaid expenses and other	(5,862)	(2,333)
Accounts payable trade and accrued liabilities	11,860	3,561
Revenues and royalties payable	18,311	18,266
Taxes payable	903	1,285
Net cash provided by operating activities	588,218	440,133
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(163,341)	(33,963)
Drilling and development capital expenditures	(660,006)	(264,015)
Proceeds from sale of oil and gas properties	1,734	7,842
Issuance of note receivable	(25,000)	-
Net cash used in investing activities	(846,613)	(290,136)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Contributions from noncontrolling interest	2,500	-
Preferred stock dividends paid	(539)	(10,781)
Long-term borrowings under credit agreement	910,000	240,000
Repayments of long-term borrowings under credit agreement	(650,000)	(370,000)
Debt issuance costs	(2,381)	-
Restricted stock used for tax withholdings	(9,048)	(5,655)
Net cash provided by (used in) financing activities	250,532	(146,436)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(7,863)	3,561
CASH AND CASH EQUIVALENTS:		
Beginning of period	18,952	11,960

End of period	$ 11,089	$ 15,521

See notes to consolidated financial statements. (Continued)

Table of Contents

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

	Six Months Ended June 30, 2011	2010
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 96,005	$ 56,158
NONCASH FINANCING ACTIVITIES:		
Contributions from noncontrolling interest	$ 5,833	$ -

See notes to consolidated financial statements. (Concluded)

Table of Contents

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

	Preferred Stock Shares	Preferred Stock Amount	Common Stock(1) Shares	Common Stock(1) Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity	Compreh Income (Loss)
ALANCES-January , 2010	3,450	$3	102,728	$51	$1,546,635	$20,413	$702,983	$2,270,085	$-	$2,270,085	
et income	-	-	-	-	-	-	211,928	211,928	-	211,928	$211,928
CI amortization on e-designated edges, net of taxes f $5,626	-	-	-	-	-	(9,633)	-	(9,633)	-	(9,633)	(9,633
otal comprehensive come											$202,295
estricted stock sued	-	-	323	-	-	-	-	-	-	-	
estricted stock rfeited	-	-	(12)	-	-	-	-	-	-	-	
estricted stock used r tax withholdings	-	-	(155)	-	(5,655)	-	-	(5,655)	-	(5,655)	
tock-based ompensation	-	-	-	-	4,390	-	-	4,390	-	4,390	
referred dividends aid	-	-	-	-	-	-	(10,781)	(10,781)	-	(10,781)	
ALANCES-June 0, 2010	3,450	$3	102,884	$51	$1,545,370	$10,780	$904,130	$2,460,334	$-	$2,460,334	
ALANCES-January , 2011	173	$-	117,968	$59	$1,549,822	$5,768	$975,666	$2,531,315	$-	$2,531,315	
et income	-	-	-	-	-	-	222,563	222,563	-	222,563	$222,563
CI amortization on e-designated edges, net of taxes f $2,011	-	-	-	-	-	(3,443)	-	(3,443)	-	(3,443)	(3,443
otal comprehensive come											$219,120
onversion of referred stock to ommon	(1)	-	1	-	-	-	-	-	-	-	
wo-for-one stock plit	-	-	-	59	(59)	-	-	-	-	-	
ontributions from oncontrolling terest	-	-	-	-	-	-	-	-	8,333	8,333	

estricted stock sued	-	-	304	-	-	-	-	-	-	-
estricted stock orfeited	-	-	(12)	-	-	-	-	-	-	-
estricted stock used or tax withholdings	-	-	(148)	-	(9,048)	-	-	(9,048)	-	(9,048)
tock-based ompensation	-	-	-	-	6,627	-	-	6,627	-	6,627
referred dividends aid	-	-	-	-	-	-	(539)	(539)	-	(539)
ALANCES-June 0, 2011	172	$-	118,113	$118	$1,547,342	$2,325	$1,197,690	$2,747,475	$8,333	$2,755,808

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

ee 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 and Whiting's pro rata share of the accounts of Whiting USA Trust I pursuant to Whiting's 15.8% ownership interest. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation. These financial statements have been prepared in accordance with GAAP for interim financial reporting. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim results. However, operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. Whiting's 2010 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in Whiting's 2010 Annual Report on Form 10-K.

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

2. ACQUISITIONS

2011 Acquisitions

On March 18, 2011, Whiting and an unrelated third party formed Sustainable Water Resources, LLC ("SWR") to develop a water project in the state of Colorado. The Company contributed $25.0 million for a 75% interest in SWR, and the 25% noncontrolling interest in SWR was ascribed a fair value of $8.3 million, which consisted of $2.5 million in cash contributions, as well as $5.8 million in intangible and fixed assets contributed to the joint venture. There were no significant results of operations attributable to the noncontrolling interest since its inception through the period ended June 30, 2011.

Table of Contents

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

2010 Acquisitions

In September 2010, Whiting acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate purchase price was $19.2 million; substantially all of which was allocated to the properties and acreage acquired. Disclosures of pro forma revenues and net income for this acquisition are not material and have not been presented accordingly.

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

3. LONG-TERM DEBT

Long-term debt consisted of the following at June 30, 2011 and December 31, 2010 (in thousands):

	June 30, 2011	December 31, 2010
Credit agreement	$460,000	$200,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$1,060,000	$800,000

Credit Agreement—Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), the Company’s wholly-owned subsidiary, has a credit agreement with a syndicate of banks. As of June 30, 2011, this credit facility had a borrowing base of $1.1 billion with $638.6 million of available borrowing capacity, which is net of $460.0 million in borrowings and $1.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2016, when the agreement expires and all outstanding borrowings are due. In April 2011, Whiting Oil and Gas entered into an amendment to its existing credit agreement that decreased the interest margins on outstanding borrowings and extended the principal repayment date from October 2015 to April 2016.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company’s proved reserves that have been mortgaged to its lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of June 30, 2011, $48.6 million was available for additional letters of credit under the agreement.

Interest accrues at the Company’s option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company also incurs commitment fees as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, and are included as a component of interest expense. At June 30, 2011, the weighted average interest rate on the outstanding principal balance under the credit agreement was

2.0%.

8

Table of Contents

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement also restricts our ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the net assets of the subsidiaries. The credit agreement requires the Company, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. The Company was in compliance with its covenants under the credit agreement as of June 30, 2011.

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

Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014. The estimated fair value of these notes was $265.6 million as of June 30, 2011, based on quoted market prices for these same debt securities.

In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. The estimated fair value of these notes was $355.3 million as of June 30, 2011, 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 2014 notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiaries, Whiting Oil and Gas and Whiting Programs, Inc. (the "2014 Guarantors"). Additionally, the Company's obligations under the 2018 notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (collectively with the 2014 Guarantors, the "Guarantors"). Any subsidiaries other than the Guarantors are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

Table of Contents

4. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at June 30, 2011 and December 31, 2010 were $6.0 million and $6.1 million, respectively, and are included in accrued liabilities and other. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. The following table provides a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2011 (in thousands):

Asset retirement obligation at January 1, 2011	$83,083
Additional liability incurred	1,027
Revisions in estimated cash flows	722
Accretion expense	3,942
Liabilities settled	(2,369)
Asset retirement obligation at June 30, 2011	$86,405

5. DERIVATIVE FINANCIAL INSTRUMENTS

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

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

Whiting Derivatives. The table below details the Company's costless collar derivatives, including its proportionate share of Whiting USA Trust I (the "Trust") derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of July 1, 2011.

Table of Contents

	Whiting Petroleum Corporation			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2011	5,426,201	211,230	$61.00 - $98.31	$6.49 - $13.94
Jan – Dec 2012	7,905,091	384,002	$59.97 - $106.27	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$47.64 - $89.90	n/a
Total	16,421,292	595,232		

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

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

	Whiting Petroleum Corporation			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2011	56,201	211,230	$74.00 - $140.44	$6.49 - $13.94
Jan – Dec 2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27
Total	161,292	595,232		

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

	Third-party Public Holders of Trust Units			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2011	176,035	661,620	$74.00 - $140.44	$6.49 - $13.94
Jan – Dec 2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27

Total	505,206	1,864,405

Discontinuance of Cash Flow Hedge Accounting—Prior to April 1, 2009, the Company designated a portion of its commodity derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to other comprehensive income. Effective April 1, 2009, however, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. As a result, such mark-to-market values at March 31, 2009 were frozen in accumulated other comprehensive income as of the de-designation date and are being reclassified into earnings as the original hedged transactions affect income. As of June 30, 2011, accumulated other comprehensive income amounted to $3.7 million ($2.3 million net of tax), which consisted entirely of unrealized deferred gains and losses on commodity derivative contracts that had been previously designated as cash flow hedges. During the next twelve months, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $3.3 million related to de-designated commodity hedges. Currently, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income.

Table of Contents

Embedded Commodity Derivative Contracts—As of June 30, 2011, Whiting had entered into certain contracts for oil field goods or services, whereby the price adjustment clauses for such goods or services are linked to changes in NYMEX crude oil prices. The Company has determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements.

Drilling Rig Contracts. As of June 30, 2011, Whiting had entered into eight contracts with drilling rig companies, whereby the rig day rates included price adjustment clauses that are linked to changes in NYMEX crude oil prices. These drilling rig contracts have various termination dates ranging from July 2011 to July 2014. The price adjustment formulas in the rig contracts stipulate that with every $10 increase or decrease in the price of NYMEX crude, the cost of drilling rig day rates to the Company will likewise increase or decrease by specific dollar amounts as set forth in each of the individual contracts. As of June 30, 2011, the aggregate estimated fair value of the embedded derivatives in these drilling rig contracts was a liability of $1.4 million.

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

CO2 Purchase Contract. In May 2011, Whiting entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in the enhanced oil recovery project that is being carried out at its North Ward Estes field in Texas. The price per Mcf of CO2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. As of June 30, 2011, the estimated fair value of the embedded derivative in this CO2 purchase contract was an asset of $1.9 million.

Although CO2 is not a commodity that is actively traded on a public exchange, the market price for CO2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO2 purchase contract where the price of CO2 is fixed and does not adjust with changes in oil prices, the Company is exposed to the risk of paying higher than the market rate for CO2 in a climate of declining oil and CO2 prices. This in turn could have a negative impact on the Company’s oil and gas well economics. As a result, the Company reduces its exposure to this risk by entering into certain CO2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

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

Table of Contents

Not Designated as ASC 815 Hedges	Balance Sheet Classification	Fair Value June 30, 2011	December 31, 2010
Derivative assets:			
Commodity contracts	Prepaid expenses and other	$ 3,680	$ 4,231
Commodity contracts	Other long-term assets	1,653	3,961
Embedded commodity contracts	Other long-term assets	1,899	-
Total derivative assets		$ 7,232	$ 8,192
Derivative liabilities:			
Commodity contracts	Current derivative liabilities	$ 61,186	$ 69,375
Embedded commodity contracts	Current derivative liabilities	634	-
Commodity contracts	Non-current derivative liabilities	97,945	95,256
Embedded commodity contracts	Non-current derivative liabilities	790	-
Total derivative liabilities		$ 160,555	$ 164,631

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, 2011 and 2010 (in thousands):

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from OCI into Income (Effective Portion) Six Months Ended June 30, 2011	2010
Commodity contracts	Gain on hedging activities	$5,454	$15,259
		Three Months Ended June 30, 2011	2010
Commodity contracts	Gain on hedging activities	$2,391	$8,525

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Six Months Ended June 30, 2011	2010
Commodity contracts	Commodity derivative (gain) loss, net	$21,294	$(78,418)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(474)	-
Total		$20,820	$(78,418)
		Three Months Ended June 30, 2011	2010
Commodity contracts	Commodity derivative (gain) loss, net	$(110,063)	$(63,496)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(3,555)	-

Total	$(113,618)	$(63,496)

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

Table of Contents

6. FAIR VALUE MEASURMENTS

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

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

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

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

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

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2011 and December 31, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value June 30, 2011
Financial Assets				
Commodity derivatives - current	$-	$3,680	$-	$3,680
Commodity derivatives - non-current	-	1,653	-	1,653
Embedded commodity derivatives - non-current	-	1,899	-	1,899
Total financial assets	$-	$7,232	$-	$7,232
Financial Liabilities				
Commodity derivatives - current	$-	$61,186	$-	$61,186
Embedded commodity derivatives - current	-	634	-	634
Commodity derivatives - non-current	-	97,945	-	97,945
Embedded commodity derivatives - non-current	-	790	-	790
Total financial liabilities	$-	$160,555	$-	$160,555

	Level 1	Level 2	Level 3	Total Fair Value

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

Table of Contents

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

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

Embedded Commodity Derivatives. Embedded commodity derivatives relate to long and short-term drilling rig contracts as well as a CO2 purchase contract, which all have price adjustment clauses that are linked to changes in NYMEX crude oil prices. Whiting has determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host drilling contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in its consolidated financial statements. These embedded commodity derivatives are valued using industry-standard models, which are based on a market approach. These models consider various assumptions, including quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company’s or the counterparty’s nonperformance risk, as appropriate.

Non-Recurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its non-recurring, non-financial measurements including business combinations, proved oil and gas property impairments and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The following table presents information about the Company’s non-financial assets and liabilities measured at fair value on a non-recurring basis as of June 30, 2011, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Net Carrying Value as of June 30, 2011	Fair Value Measurement Using			Pre-tax (Gain) Loss Six Months Ended June 30, 2011
		Level 1	Level 2	Level 3	
Noncontrolling interest	$8,333	$ -	$ -	$ 8,333	$-
Asset retirement obligations	1,041	-	-	1,027	-
Total non-recurring assets at fair value	$9,374	$ -	$ -	$ 9,360	$-

15

Table of Contents

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

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

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

7. DEFERRED COMPENSATION

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

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the six months ended June 30, 2011 and 2010 amounted to $17.1 million and $14.1 million, respectively, charged to general and administrative expense and $2.2 million and $1.9 million, respectively, charged to exploration expense.

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

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At June 30, 2011, the Company used three-year average historical NYMEX prices of $79.97 for crude oil and $4.92 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control of the Company (as defined in the Plan), all employees fully vest and the Company would distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on current strip prices at June 30, 2011, if the Company elected to terminate the Plan or if a change of control event occurred, it is estimated that the fully vested lump sum cash payment to employees would approximate $173.8 million. This amount includes $19.9 million attributable to proved undeveloped oil and gas properties and $19.3 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2012. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

Table of Contents

The following table presents changes in the Plan's estimated long-term liability for the six months ended June 30, 2011 (in thousands):

Long-term Production Participation Plan liability at January 1, 2011	$81,524
Change in liability for accretion, vesting, change in estimates and new Plan year activity	21,481
Cash payments accrued as compensation expense and reflected as a current payable	(19,274)
Long-term Production Participation Plan liability at June 30, 2011	$83,731

8. SHAREHOLDERS' EQUITY

Common Stock—In May 2011, Whiting's stockholders approved an amendment to the Company's Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 175,000,000 shares to 300,000,000 shares.

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

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share.

Each holder of the preferred stock is entitled to an annual dividend of $6.25 per share to be paid quarterly in cash, common stock or a combination thereof on March 15, June 15, September 15 and December 15, when and if such dividend has been declared by Whiting's board of directors. Each share of preferred stock has a liquidation preference of $100.00 per share plus accumulated and unpaid dividends and is convertible, at a holder's option, into shares of Whiting's common stock based on a conversion price of $21.70815, subject to adjustment upon the occurrence of certain events. The preferred stock is not redeemable by the Company. At any time on or after June 15, 2013, the Company may cause all outstanding shares of this preferred stock to be converted into shares of common stock if the closing price of our common stock equals or exceeds 120% of the then-prevailing conversion price for at least 20 trading days in a period of 30 consecutive trading days. The holders of preferred stock have no voting rights unless dividends payable on the preferred stock are in arrears for six or more quarterly periods.

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

Table of Contents

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, 2011 and 2010 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to pre-tax income primarily because of state income taxes and estimated permanent differences.

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

10. EARNINGS PER SHARE

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

	Three Months Ended June 30,	
	2011	2010
Basic Earnings Per Share(1)		
Numerator:		
Net income	$203,149	$125,317
Preferred stock dividends	(269)	(5,391)
Net income available to common shareholders, basic	$202,880	$119,926
Denominator:		
Weighted average shares outstanding, basic	117,373	101,989
Diluted Earnings Per Share(1)		
Numerator:		
Net income available to common shareholders, basic	$202,880	$119,926
Preferred stock dividends	269	5,391
Adjusted net income available to common shareholders, diluted	$203,149	$125,317
Denominator:		
Weighted average shares outstanding, basic	117,373	101,989
Restricted stock and stock options	492	567
Convertible perpetual preferred stock	794	15,893
Weighted average shares outstanding, diluted	118,659	118,449
Earnings per common share, basic	$1.73	$1.18
Earnings per common share, diluted	$1.71	$1.06

(1) All share and per share amounts have been retroactively restated for the three months ended June 30, 2010 to reflect the Company's February 2011 two-for-one stock split described in Note 8 to these consolidated financial statements.

Table of Contents

	Six Months Ended June 30, 2011	2010
Basic Earnings Per Share(1)		
Numerator:		
Net income	$222,563	$211,928
Preferred stock dividends	(539)	(10,781)
Net income available to common shareholders, basic	$222,024	$201,147
Denominator:		
Weighted average shares outstanding, basic	117,308	101,906
Diluted Earnings Per Share(1)		
Numerator:		
Net income available to common shareholders, basic	$222,024	$201,147
Preferred stock dividends	539	10,781
Adjusted net income available to common shareholders, diluted	$222,563	$211,928
Denominator:		
Weighted average shares outstanding, basic	117,308	101,906
Restricted stock and stock options	605	670
Convertible perpetual preferred stock	794	15,893
Weighted average shares outstanding, diluted	118,707	118,469
Earnings per common share, basic	$1.89	$1.97
Earnings per common share, diluted	$1.87	$1.79

(1) All share and per share amounts have been retroactively restated for the six months ended June 30, 2010 to reflect the Company's February 2011 two-for-one stock split described in Note 8 to these consolidated financial statements.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"), which provides amendments to FASB ASC Topic 820, Fair Value Measurement. The objective of ASU 2011-04 is to create common fair value measurement and disclosure requirements between GAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify existing fair value measurement and disclosure requirements and make changes to particular principles or requirements for measuring or disclosing information about fair value measurements. These amendments are not expected to have a significant impact on companies applying GAAP. ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this standard will not have an impact on the Company's consolidated financial statements other than additional disclosures.

Table of Contents

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income ("ASU 2011-05"), which provides amendments to FASB ASC Topic 220, Comprehensive Income. The objective of ASU 2011-05 is to require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of equity. ASU 2011-05 is effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The adoption of this standard will not have an impact on the Company's consolidated financial statements other than requiring the Company to present its statements of comprehensive income separately from its statements of equity, as these statements are currently presented on a combined basis.

12. SUBSEQUENT EVENT

On July 28, 2011, the Company completed the acquisition of approximately 23,400 net acres and one well in the Missouri Breaks prospect in Richland County, Montana for an unadjusted purchase price of $46.9 million and with an effective date of May 1, 2011.

Table of Contents

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

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

Overview

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

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

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

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

Our revenue, profitability and future growth rate depend on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2010:

21

Table of Contents

	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011
Crude Oil	$78.79	$77.99	$76.21	$85.18	$94.25	$102.55
Natural Gas	$5.30	$4.09	$4.39	$3.81	$4.10	$4.32

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant non-cash, mark-to-market losses being recognized on our commodity derivatives, which may in turn cause us to experience net losses.

2011 Highlights and Future Considerations

Operational Highlights.

Sanish. Our Sanish field in Mountrail County, North Dakota targets the Bakken and Three Forks formations. Net production in the Sanish field decreased 5% from 21.7 MBOE/d in the first quarter of 2011 to 20.5 MBOE/d in the second quarter of 2011. The decrease in production was due to well completion delays and downtime resulting from inclement weather in North Dakota. After three weeks of mostly dry weather, we are making progress fracture stimulating new wells and returning wells to production. We currently have two full-time dedicated fracture stimulation crews and one half-time fracture stimulation crew working in this area and expect to reduce our inventory of operated wells awaiting completion in the Williston Basin from 44 as of July 15, 2011 to below 25 by November 30, 2011.

From April 15 through July 15, 2011, we completed five operated Bakken wells and three operated Three Forks wells in the Sanish field, bringing to 171 the total number of operated wells in the field. As of July 15, 2011, 29 operated wells were being completed or awaiting completion and eight operated wells were being drilled in the Sanish field. In 2011, we intend to drill a total of 95 gross (52.7 net) operated wells in the Sanish field, of which 70 are planned Three Forks wells. We plan to continue with our current nine operated drilling rig count in the Sanish field through 2013.

Robinson Lake Gas Plant. At our Robinson Lake gas plant in North Dakota, we recently added a fractionation facility and a second NGL train. The plant's current inlet compression capacity is 70 MMcf/d, and we plan to add compression capacity as the processing demand increases. As of July 8, 2011, the plant was processing 39.6 MMcf/d of production from our Sanish field.

Lewis & Clark. Our Lewis & Clark prospect area is located primarily in Stark County, North Dakota and runs along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Three Forks formation. We hold a working interest in 250 1,280-acre spacing units in Lewis & Clark. From April 15 through July 15, 2011, we completed 10 operated wells in the Lewis & Clark field, bringing the total number of operated wells in the field to 26. As of July 15, 2011, nine operated wells were being completed or awaiting completion and six operated wells were being drilled. We currently have six drilling rigs operating in this prospect, and we plan to have an average of eight rigs working from September through December 2011. Based on well results to date, we plan to increase drilling activity in the Stark and Billings counties portions of this prospect in the second half of 2011. In early April 2011, we broke ground on the construction of a gas processing plant at Lewis & Clark, which is expected to be completed by November 2011.

22

Table of Contents

Hidden Bench. Our Hidden Bench prospect in McKenzie County, North Dakota targets the Bakken formation. Based on well results to date, we plan to drill a total of 11 operated wells in this prospect in 2011.

North Ward Estes. The North Ward Estes field is located in the Ward and Winkler Counties in Texas, and we continue to have significant development and related infrastructure activity in this field since we acquired it in 2005. Our activity at North Ward Estes to date has resulted in reserve additions and production increases, and our expansion of the CO_2 flood in this area continues to generate positive results.

North Ward Estes has been responding positively to the water and CO_2 floods that we initiated in May 2007. In the second quarter of 2011, production from North Ward Estes averaged 8.1 MBOE/d representing a 6% increase from second quarter 2010 levels. During June 2011, we experienced under-deliveries of CO_2 contract quantities from our North Ward Estes CO_2 supplier. The shortfall in June was approximately 25 MMcf/d below our contracted delivery volume of 134 MMcf/d. The supplier attributes the shortfall primarily to a production imbalance that it is making up currently to a co-owner of the McElmo Dome. For most of July 2011, our daily CO_2 deliveries have increased to approximately 122 MMcf/d, and the supplier has informed us that they plan to resume delivery of full contract quantities by September 30, 2011. We are currently injecting approximately 250 MMcf/d of CO_2 into the field, of which about 60% is recycled.

We recently signed a 15-year CO_2 supply agreement to purchase CO_2 from 2015 through 2029 for use in our enhanced oil recovery project at the North Ward Estes field. We also recently executed another CO_2 supply contract and an amendment to that contract for additional CO_2 over a six-year period, beginning January 1, 2012. We estimate that we will have sufficient supplies of CO_2 to fully execute our development plans at North Ward Estes for several years. The first two phases of our development plan were largely completed by December 2009, Phase III began in December 2010 and Phase IV is expected to be implemented before year-end 2011.

Postle. The Postle field is located in Texas County, Oklahoma and produces from the Morrow sandstone. Postle averaged 8.1 MBOE/d in the second quarter of 2011, which represents a 15% decrease from the 9.6 MBOE/d produced in the second quarter of 2010 primarily due to cold weather and the resulting paraffin issues experienced at this field.

Redtail. Our Redtail prospect in Weld County, Colorado targets the Niobrara formation. Based on recent well results, we have added four wells in this area to our 2011 drilling program.

Seep Ridge Gas Pipeline. On April 16, 2011, our Seep Ridge Gas Pipeline in Uintah County, Utah was shut-in for repairs. The pipeline was back on stream June 14, 2011 and is currently flowing at full capacity. We are transporting net gas of 21.9 MMcf/d from the Flat Rock and Chimney Rock fields.

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

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

In May 2011, our stockholders approved an amendment to the Company's Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 175,000,000 shares to 300,000,000 shares.

Table of Contents

Results of Operations

Six Months Ended June 30, 2011 Compared to Six Months Ended June 30, 2010

Selected Operating Data:	Six Months Ended June 30, 2011	2010
Net production:		
Oil (MMBbls)	9.6	9.1
Natural gas (Bcf)	13.3	13.2
Total production (MMBOE)	11.8	11.3
Net sales (in millions):		
Oil (1)	$833.5	$636.8
Natural gas (1)	66.0	66.9
Total oil and natural gas sales	$899.5	$703.7
Average sales prices:		
Oil (per Bbl)	$87.18	$70.23
Effect of oil hedges on average price (per Bbl)	(2.56)	(1.33)
Oil net of hedging (per Bbl)	$84.62	$68.90
Average NYMEX price (per Bbl)	$98.42	$78.39
Natural gas (per Mcf)	$4.97	$5.07
Effect of natural gas hedges on average price (per Mcf)	0.04	0.04
Natural gas net of hedging (per Mcf)	$5.01	$5.11
Average NYMEX price (per Mcf)	$4.21	$4.69
Cost and expense (per BOE):		
Lease operating expenses	$12.34	$11.41
Production taxes	$5.60	$4.54
Depreciation, depletion and amortization expense	$18.51	$17.05
General and administrative expenses	$3.34	$2.58

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $195.8 million to $899.5 million in the first half of 2011 compared to the same period in 2010. Sales are a function of oil and gas volumes sold and average sales prices. Our oil sales volumes increased 5% between periods, while our natural gas sales volumes increased 1%. The oil volume increase resulted primarily from drilling successes at our Lewis & Clark field and in the North Dakota Bakken area. Oil production from our Lewis & Clark field in the first half of 2011 increased 310 MBbl compared to the first half of 2010, while oil production from the Bakken increased 275 MBbl over the same prior year period. These production increases were partially offset by a decrease in oil production volumes of 195 MBbl at the Postle field due to cold weather and the resulting paraffin issues. The gas volume increase between periods was primarily the result of 1,385 MMcf of higher gas production at our Flat Rock field due to new wells drilled and completed there during the last twelve months. This gas production increase was largely offset by normal field production decline across many of our areas.

Also contributing to the increase in oil and gas sales revenue in 2011 was an increase in the average sales price for oil. Our average price for oil before the effects of hedging increased 24% between periods. This increase was partially offset by a 2% decrease in our average price for natural gas before the effects of hedging.

Gain on Hedging Activities. Our gain on hedging activities decreased $9.8 million in 2011 as compared to the first half of 2010, and it consisted of the following (in thousands):

Table of Contents

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Gains reclassified from AOCI on de-designated hedges	$5,454	$15,259

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

See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of July 1, 2011.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first half of 2011 were $145.3 million, a $16.7 million increase over the same period in 2010. Our lease operating expenses on a BOE basis also increased from $11.41 during the first half of 2010 to $12.34 during the first half of 2011. This rise in LOE in 2011 was related to a higher level of workover activity, as well as a $6.5 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months. Workovers increased to $41.2 million in the first half of 2011, as compared to $31.0 million in the first half of 2010, primarily due to a higher number of well workovers being conducted on our two main CO2 projects.

Production Taxes. Our production taxes during the first half of 2011 were $65.9 million, a $14.8 million increase over the same period in 2010, which increase was primarily due to higher oil and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and we take advantage of credits and exemptions allowed in our various taxing jurisdictions. As a percentage of oil and gas sales before the effects of hedging, our company-wide production tax rates for the first half of 2011 and 2010 remained constant at 7.3%.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $25.8 million in 2011 as compared to the first half of 2010. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Depletion	$212,832	$187,569
Depreciation	1,204	1,005
Accretion of asset retirement obligations	3,942	3,558
Total	$217,978	$192,132

DD&A increased in the first half of 2011 primarily due to $25.3 million in higher depletion expense between periods. This increase was the result of $16.8 million in higher depletion due to an increase in our depletion rate between periods and $8.5 million in higher depletion due to a rise in overall production volumes during the first half of 2011. On a BOE basis, our DD&A rate of $18.51 for the first half of 2011 was 9% higher than the rate of $17.05 for the same period in 2010. The higher DD&A rate was mainly due to $1,129.5 million in drilling and development expenditures paid during the past twelve months, which was partially offset by a net increase in our estimated proved reserves of 29.8 MMBOE as of December 31, 2010.

25

Table of Contents

Exploration and Impairment Costs. Our exploration and impairment costs increased $15.0 million in the first half of 2011, as compared to the first half of 2010. The components of our exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Exploration	$26,966	$19,715
Impairment	15,442	7,700
Total	$42,408	$27,415

Exploration costs increased $7.3 million during the first half of 2011 as compared to the same period in 2010 primarily due to an increase in geological and geophysical ("G&G") activity and higher exploratory dry hole costs. G&G costs, such as seismic studies, amounted to $11.9 million during the first half of 2011 as compared to $9.7 million during the same period in 2010. During the six months ended June 30, 2011, we drilled three exploratory dry holes in the Rocky Mountains, Permian Basin and Gulf Coast regions totaling $4.3 million, while we drilled one exploratory dry hole in the Gulf Coast region totaling $2.6 million during the first half of 2010. Impairment expense in the first half of 2011 and 2010 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. A higher amount of undeveloped leasehold costs were amortized to impairment on a group basis for the six months ended June 30, 2011 as compared to the first half of 2010.

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
General and administrative expenses	$71,434	$55,392
Reimbursements and allocations	(32,108)	(26,356)
General and administrative expense, net	$39,326	$29,036

General and administrative expenses before reimbursements and allocations increased $16.0 million during the first half of 2011 as compared to the same period in 2010 primarily due to higher employee compensation and an increase in accrued Production Participation Plan ("Plan") distributions. Employee compensation increased $11.8 million in the first half of 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased $3.3 million between periods. The increase in reimbursements and allocations in the first half of 2011 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 4% for the first half of 2010 and 2011.

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

Table of Contents

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Senior Subordinated Notes	$20,125	$22,162
Credit agreement	6,988	4,108
Amortization of debt issue costs and debt discount	4,241	5,024
Other	55	813
Capitalized interest	(1,672)	(783)
Total	$29,737	$31,324

The decrease in interest expense of $1.6 million between periods was mainly due to lower interest of $2.0 million on our Senior Subordinated Notes that resulted from redeeming $150.0 million of 7.25% notes and $220.0 million of 7.25% notes in early September 2010. Also in September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018. In addition, we incurred higher amounts of capitalized interest between periods due to an increase in costs capitalized on projects requiring longer than six months to be substantially complete and ready for use. These decreases in interest were partially offset by higher borrowings outstanding under our credit agreement during the first half of 2011, which increased interest expense on our credit agreement by $2.9 million. Our weighted average debt outstanding during the first half of 2011 was $1,019.9 million versus $745.2 million for the first half of 2010. Our weighted average effective cash interest rate was 5.3% during the first half of 2011 compared to 7.1% during the first half of 2010.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty. Cash settlement gains and losses on derivative contracts that are not embedded derivatives are also recorded immediately to earnings as commodity derivative (gain) loss, net. The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Change in unrealized (gains) losses on derivative contracts	$(3,115)	$(89,977)
Realized cash settlement losses	23,935	11,559
Total	$20,820	$(78,418)

With respect to our open derivative contracts at June 30, 2011 and 2010, the futures curve of forecasted commodity prices (“forward price curve”) for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of each respective period. The change in unrealized (gains) losses on derivative contracts in the first half of 2011 resulted in a $3.1 million gain on such net liability position due to the downward shift in the forward price curve for NYMEX crude oil from January 1 to June 30, 2011. The change in unrealized (gains) losses on derivative contracts in the first half of 2010 resulted in a $90.0 million gain due to a more significant downward shift in the same forward price curve from January 1 to June 30, 2010.

Income Tax Expense. Income tax expense totaled $127.2 million for the first six months of 2011, as compared to $130.1 million of income tax for the first six months of 2010. Our effective income tax rate decreased to 36.4% for the first half of 2011 as compared to a rate of 38.0% for the same period in 2010. This change in our effective income tax rate was primarily attributable to recent North Dakota corporate tax legislation, which created a one-time benefit in the first half of 2011. Our effective tax rates for the periods ended June 30, 2011 and 2010 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences.

Table of Contents

Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010

Selected Operating Data:	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Net production:		
Oil (MMBbls)	4.8	4.8
Natural gas (Bcf)	6.3	6.6
Total production (MMBOE)	5.8	5.9
Net sales (in millions):		
Oil (1)	$442.8	$333.0
Natural gas (1)	31.1	30.0
Total oil and natural gas sales	$473.9	$363.0
Average sales prices:		
Oil (per Bbl)	$92.50	$69.78
Effect of oil hedges on average price (per Bbl)	(3.40)	(0.68)
Oil net of hedging (per Bbl)	$89.10	$69.10
Average NYMEX price (per Bbl)	$102.55	$77.99
Natural gas (per Mcf)	$4.94	$4.52
Effect of natural gas hedges on average price (per Mcf)	0.03	0.04
Natural gas net of hedging (per Mcf)	$4.97	$4.56
Average NYMEX price (per Mcf)	$4.32	$4.09
Cost and expense (per BOE):		
Lease operating expenses	$12.65	$11.52
Production taxes	$5.87	$4.43
Depreciation, depletion and amortization expense	$18.89	$16.09
General and administrative expenses	$3.58	$2.62

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $110.8 million to $473.9 million in the second quarter of 2011 compared to the same period in 2010. Sales are a function of oil and gas prices and production volumes sold. Our average price for oil before the effects of hedging increased 33% between periods and our average price for natural gas before the effects of hedging increased 9%. These increases in average sales prices in 2011 were partially offset by decreases in sales volumes between periods. Our oil sales volumes remained relatively constant between periods, while our natural gas sales volumes decreased 5%. We experienced drilling success at our Lewis & Clark field where oil production increased 215 MBbl compared to the second quarter of 2010. This production increase was offset by a production volume decrease of 125 MBbl at the Postle field due to cold weather and the resulting paraffin issues and a decrease of 120 MBbl at our North Dakota Bakken area, where inclement weather conditions caused well completion delays. The gas volume decrease of 5% between periods was primarily the result of normal field production decline across many of our areas, as well as gas production volume decreases at our North Dakota Bakken area due to the negative impact of adverse weather conditions. These production decreases were partially offset by increased gas production of 165 MMcf at our Flat Rock field due to new wells drilled and completed in that area during the last twelve months.

Gain on Hedging Activities. Our gain on hedging activities decreased $6.1 million in 2011 as compared to the second quarter of 2010, and it consisted of the following (in thousands):

Table of Contents

	Three Months Ended June 30,	
	2011	2010
Gains reclassified from AOCI on de-designated hedges	$2,391	$8,525

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

See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of July 1, 2011.

Lease Operating Expenses. Our lease operating expenses during the second quarter of 2011 were $73.8 million, a $6.1 million increase over the same period in 2010. Our lease operating expenses on a BOE basis also increased from $11.52 during the second quarter of 2010 to $12.65 during the second quarter of 2011. This rise in LOE in 2011 was primarily related to increases in the cost of oil field goods and services associated with net wells we added during the last twelve months.

Production Taxes. Our production taxes during the second quarter of 2011 were $34.3 million, an $8.2 million increase over the same period in 2010, which increase was primarily due to higher oil and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and we take advantage of credits and exemptions allowed in our various taxing jurisdictions. As a percentage of oil and gas sales before the effects of hedging, our company-wide production tax rates for the second quarter of 2011 and 2010 remained constant at 7.2%.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expense increased $15.7 million in 2011 as compared to the second quarter of 2010. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30,	
	2011	2010
Depletion	$107,622	$92,245
Depreciation	633	514
Accretion of asset retirement obligations	1,995	1,824
Total	$110,250	$94,583

DD&A increased in the second quarter of 2011 primarily due to $15.4 million in higher depletion expense between periods. This increase was the result of $16.1 million in higher depletion due to an increase in our depletion rate between periods, which effect was partially offset by $0.7 million in lower depletion expense due to a slight decline in overall production volumes when comparing production in the second quarter 2011 to second quarter 2010. On a BOE basis, our DD&A rate of $18.89 for the second quarter of 2011 was up from the rate of $16.09 for the same period in 2010. The higher DD&A rate was mainly due to $1,129.5 million in drilling and development expenditures paid during the past twelve months, which was partially offset by a net increase in our estimated proved reserves of 29.8 MMBOE as of December 31, 2010.

Exploration and Impairment Costs. Our exploration and impairment costs increased $5.7 million in the second quarter of 2011, as compared to the second quarter of 2010. The components of our exploration and impairment costs were as follows (in thousands):

Table of Contents

	Three Months Ended June 30,	
	2011	2010
Exploration	$12,367	$10,652
Impairment	7,804	3,857
Total	$20,171	$14,509

Exploration costs increased $1.7 million during the second quarter of 2011 as compared to the same period in 2010 primarily due to an increase of $1.7 million in geology related general and administrative expenses. Impairment expense in the second quarter of 2011 and 2010 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. A higher amount of undeveloped leasehold costs were amortized to impairment on a group basis during the second quarter of 2011 as compared to the second quarter of 2010.

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

	Three Months Ended June 30,	
	2011	2010
General and administrative expenses	$37,446	$28,440
Reimbursements and allocations	(16,533)	(13,038)
General and administrative expense, net	$20,913	$15,402

General and administrative expenses before reimbursements and allocations increased $9.0 million during the second quarter of 2011 as compared to the same period in 2010 primarily due to higher employee compensation and an increase in accrued Plan distributions. Employee compensation increased $6.6 million in the second quarter of 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased $2.1 million between periods. The increase in reimbursements and allocations in the second quarter of 2011 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 4% for the second quarters of 2010 and 2011.

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

	Three Months Ended June 30,	
	2011	2010
Senior Subordinated Notes	$10,063	$11,081
Credit agreement	3,795	1,963
Amortization of debt issue costs and debt discount	2,114	2,508
Other	37	437
Capitalized interest	(730)	(357)
Total	$15,279	$15,632

Table of Contents

The decrease in interest expense of $0.4 million between periods was mainly due to lower interest of $1.0 million on our Senior Subordinated Notes that resulted from redeeming $150.0 million of 7.25% notes and $220.0 million of 7.25% notes in early September of 2010. Also in September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018. In addition, we incurred higher amounts of capitalized interest between periods due to an increase in costs capitalized on projects requiring longer than six months to be substantially complete and ready for use. These decreases in interest were partially offset by higher borrowings outstanding under our credit agreement during the second quarter of 2011, which increased interest expense on our credit agreement by $1.8 million. Our weighted average debt outstanding during the second quarter of 2011 was $1,107.7 million versus $719.5 million for the second quarter of 2010. Our weighted average effective cash interest rate was 5.0% during the second quarter of 2011 compared to 7.3% during the second quarter of 2010.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty. Cash settlement gains and losses on derivative contracts that are not embedded derivatives are also recorded immediately to earnings as commodity derivative (gain) loss, net. The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Three Months Ended June 30,	
	2011	2010
Change in unrealized (gains) losses on derivative contracts	$(129,723)	$(66,491)
Realized cash settlement losses	16,105	2,995
Total	$(113,618)	$(63,496)

With respect to our open derivative contracts at June 30, 2011 and 2010, the futures curve of forecasted commodity prices (“forward price curve”) for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of each respective period. The change in unrealized (gains) losses on derivative contracts in the second quarter of 2011 resulted in a $129.7 million gain in such net liability position due to the significant downward shift in the forward price curve for NYMEX crude oil from April 1 to June 30, 2011. The change in unrealized (gains) losses on derivative contracts in the second quarter of 2010 resulted in a $66.5 million gain due to a less significant downward shift in the same forward price curve from April 1 to June 30, 2010.

Income Tax Expense. Income tax expense totaled $114.4 million for the second quarter of 2011, as compared to $77.2 million of income tax for the second quarter of 2010. However, our effective income tax rate decreased to 36.0% for the second quarter of 2011 as compared to a rate of 38.1% for the same period in 2010. This change in our effective income tax rate was primarily attributable to recent North Dakota corporate tax legislation, which created a one-time benefit in the second quarter of 2011. Our effective tax rates for the periods ended June 30, 2011 and 2010 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences.

Table of Contents

Liquidity and Capital Resources

Overview. At June 30, 2011, our debt to total capitalization ratio was 27.8%, we had $11.1 million in cash on hand and $2,755.8 million of equity. At December 31, 2010, our debt to total capitalization ratio was 24.0%, we had $19.0 million of cash on hand and $2,531.3 million of equity. In the first half of 2011, we generated $588.2 million of cash provided by operating activities, an increase of $148.1 million over the same period in 2010. Cash provided by operating activities increased primarily due to higher average sales prices for crude oil as well as higher crude oil and natural gas production volumes. These positive factors were partially offset by lower average sales prices for natural gas in the first half of 2011, as well as increased lease operating expenses, production taxes, G&G costs and general and administrative expenses during the first half of 2011 as compared to the same period in 2010. Cash flows from operating activities and net borrowings under our credit agreement totaling $260.0 million were used to finance $660.0 million of drilling and development expenditures, $163.3 million of cash acquisition capital expenditures paid in the first six months of 2011 and the issuance of a $25.0 million note receivable. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during the first six months of 2011 (in thousands):

	Drilling and Development Expenditures (1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 448,078	$ 102,350	$ 12,532	$ 562,960	69 %
Permian Basin	153,327	16,699	11,703	181,729	22 %
Mid-Continent	52,818	-	1,190	54,008	7 %
Gulf Coast	5,611	25	1,481	7,117	1 %
Michigan	7,091	185	60	7,336	1 %
Total incurred	666,925	119,259	26,966	813,150	100 %
Increase in accrued capital expenditures	(11,216)	-	-	(11,216)	
Total paid	$ 655,709	$ 119,259	$ 26,966	$ 801,934	

(1) For purposes of this schedule, exploratory dry hole costs of $4.3 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2011 capital budget is $1,600.0 million. This represents a 64% increase from the $978.3 million incurred on exploration, development and acreage expenditures during 2010. We expect to fund our 2011 capital budget with net cash provided by our operating activities as well as with borrowings under our credit facility. We have increased our 2011 capital budget from our actual level of 2010 expenditures in response to higher oil prices experienced in 2010 and continuing into the first half of 2011, higher crude oil production volumes projected for 2011, our development of projects expected to generate attractive rates of return, and additional purchases of undeveloped acreage anticipated in 2011. Although we have only budgeted $200.0 million for acreage acquisitions in 2011, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should additional attractive acquisition opportunities arise or exploration and development expenditures exceed $1,600.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, or agreements with industry partners. Our level of exploration, development and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments; comply with our debt covenants; and meet other obligations that may arise from our oil and gas operations.

Table of Contents

Credit Agreement. Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of June 30, 2011 had a borrowing base of $1.1 billion with $638.6 million of available borrowing capacity, which was net of $460.0 million in borrowings and $1.4 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of June 30, 2011, $48.6 million was available for additional letters of credit under the agreement.

The amended credit agreement provides for interest only payments until April 2016, when the entire amount borrowed is due. Interest accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of the net assets of the subsidiaries. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. We were in compliance with its covenants under the credit agreement as of June 30, 2011.

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

Table of Contents

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

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liability of $103.0 million (which amount comprises both the long and short-term portions of this obligation) as of June 30, 2011, 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, 2011 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a)	$1,060,000	$-	$250,000	$460,000	$350,000
Cash interest expense on debt (b)	253,895	49,380	91,468	61,859	51,188
Derivative contract liability fair value (c)	160,555	61,820	98,735	-	-
Asset retirement obligation (d)	86,405	6,036	7,619	7,315	65,435
Tax sharing liability (e)	23,513	1,786	3,187	18,540	-
Purchasing obligations (f)	858,375	49,694	134,854	239,224	434,603
Drilling rig contracts (g)	210,678	77,987	128,339	4,352	-
Operating leases (h)	10,261	4,132	5,401	672	56
Total	$2,663,682	$250,835	$719,603	$791,962	$901,282

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

(b) Cash interest expense on the 7% Senior Subordinated Notes due 2014 and the 6.5% Senior Subordinated Notes due 2018 is estimated assuming no principal repayment until the due date of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date and is estimated at a fixed interest rate of 2.0%.

(c) The above derivative obligation at June 30, 2011 consists of a $155.2 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations. With respect to our open derivative contracts at June 30, 2011 with certain counterparties, the forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk and commodity price volatility. The above derivative obligation at June 30, 2011 also consists of a $4.0 million payable to Whiting USA Trust I (the "Trust") for derivative contracts that we have entered into but have in turn conveyed to the Trust. Although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to the Trust under the terms of the conveyance. The remaining $1.4 million derivative fair value liability relates to embedded commodity-based derivatives.

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

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

(f) We have four take-or-pay purchase agreements, two agreements expiring in December 2014, one agreement expiring in December 2017 and one agreement expiring in December 2029, whereby we have committed to buy certain volumes of CO2 for use in enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with three different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. In addition, we have two ship-or-pay agreements with two different parties, one expiring in June 2013 and one expiring in December 2017, whereby we have committed to transport a minimum daily volume of CO2 via certain pipelines or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes specified in these agreements. Therefore, we expect to avoid any payments for deficiencies. The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts. However, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

Table of Contents

(g) We currently have eleven drilling rigs under long-term contract, of which two drilling rigs expire in 2012, three in 2013 and six in 2014. All of these rigs are operating in the Rocky Mountains region. As of June 30, 2011, early termination of the remaining contracts would require termination penalties of $145.9 million, which would be in lieu of paying the remaining drilling commitments of $210.7 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(h) We lease 135,026 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, 46,700 square feet of office space in Midland, Texas expiring in 2012 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016.

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

New Accounting Pronouncements

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

Critical Accounting Policies and Estimates

Information regarding critical accounting policies and estimates is contained in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

Effects of Inflation and Pricing

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

Forward-Looking Statements

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

Table of Contents

These risks and uncertainties include, but are not limited to: declines in oil or natural gas prices; impacts of the global recession and tight credit markets; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain CO2; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; federal and state initiatives relating to the regulation of hydraulic fracturing; the potential impact of federal debt reduction initiatives and tax reform legislation being considered by the U.S. Federal government that could have a negative effect on the oil and gas industry; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

Commodity Derivative Contracts—Our outstanding hedges as of July 1, 2011 are summarized below:

Whiting Petroleum Corporation

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

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (the "Trust"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 666 MBbls of crude oil and 2,460 MMcf of natural gas from 2011 through 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

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

Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	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	07/2011 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

Table of Contents

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil contracts listed in both tables above, a hypothetical $10.00 per Bbl change in the NYMEX forward curve as of June 30, 2011 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $110.6 million. For the natural gas contracts listed above, a hypothetical $1.00 per Mcf change in the NYMEX forward curve as of June 30, 2011 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $0.4 million.

We have various fixed price gas sales contracts with end users for a portion of the natural gas we produce in Colorado, Michigan and Utah. Our estimated future production volumes to be sold under these fixed price contracts as of July 1, 2011 are summarized below:

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

Embedded Commodity Derivative Contracts—The price we pay for oil field products and services significantly impacts our profitability, reserve estimates, access to capital and future growth rate. Typically, as prices for oil and natural gas increase, so do all associated costs. We have entered into certain contracts for oil field goods and services with price adjustment clauses that are linked to changes in NYMEX crude oil prices to reduce our exposure to paying higher than the market rates for these goods and services in a climate of declining oil prices. We have determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and we have therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements. These embedded commodity derivative contracts have not been designated as hedges, and therefore all changes in fair value since inception have been recorded immediately to earnings.

As of June 30, 2011, we had eight contracts with drilling rig companies, whereby the rig day rates increased or decreased along with changes in the price of NYMEX crude oil. These drilling rig contracts have various termination dates ranging from July 2011 to July 2014. For these embedded commodity derivative contracts, a hypothetical $10.00 per Bbl change in the NYMEX forward curve as of June 30, 2011 would cause a change in our commodity derivative (gain) loss of $2.2 million.

In May 2011, we entered into a long-term contract to purchase CO_2 from 2015 through 2029 for use in our enhanced oil recovery project at our North Ward Estes field in Texas. The price per Mcf of CO_2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. For this embedded commodity derivative contract, a hypothetical $10.00 per Bbl change in the NYMEX forward curve as of

June 30, 2011 would cause a change in our commodity derivative (gain) loss of $12.1 million.

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 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, 2011. Based upon their evaluation of these disclosures controls and procedures, the Chairman and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of June 30, 2011 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

In November 2010, Whiting previously disclosed a well incident at the Roggenbuck 14-25H well in North Dakota in which a valve near the wellhead failed resulting in water, oil and natural gas flowing from the well, with Whiting containing and hauling from the well site the liquids being produced. Whiting received a complaint, dated February 15, 2011, in an administrative action by the North Dakota Industrial Commission (the "NDIC") alleging that in connection with such incident Whiting violated certain sections of the North Dakota Administrative Code governing the oil and gas industry, including by not controlling subsurface pressure on a well, by allowing oil and brine to flow over and pool on the surface of the land and by not properly maintaining a dike on the well site. The incident described above was of relatively short duration, was fully and promptly remediated and there were no injuries. Whiting and the NDIC entered into a consent agreement in June 2011 in which the administrative complaint was dismissed with prejudice without any admission of liability by Whiting. Pursuant to the consent agreement, Whiting agreed to (i) reimburse the NDIC for its costs and expenses of $4,357, (ii) contribute $15,000 to the North Dakota Abandoned Oil and Gas Well Plugging and Site Reclamation Fund and (iii) construct specified containment dikes and install frac strings inside the intermediate casing on each well drilled within one mile of certain designated water bodies until the earlier of December 31, 2012 or the date new rules covering dikes and frac strings are promulgated.

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. No material change to such risk factors has occurred during the six months ended June 30, 2011.

Item 6. Exhibits

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

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 29th day of July, 2011.

WHITING PETROLEUM CORPORATION

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

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

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

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Certificate of Amendment to the Restated Certificate of Incorporation of Whiting Petroleum Corporation.
(3.2)	Restated Certificate of Incorporation of Whiting Petroleum Corporation.
(31.1)	Certification by the Chairman and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(101)	The following materials from Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 are furnished herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of June 30, 2011 and December 31, 2010, (ii) the Consolidated Statements of Income for the Three and Six Months Ended June 30, 2011 and 2010, (iii) the Consolidated Statements of Cash Flow for the Six Months Ended June 30, 2011 and 2010, (iv) the Consolidated Statements of Equity and Comprehensive Income for the Six Months Ended June 30, 2011 and 2010, and (v) Notes to Consolidated Financial Statements.