WHITING PETROLEUM CORP
Form 10-Q
July 26, 2007

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, 2007**

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer T Accelerated filer £ Non-accelerated filer £

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 16, 2007: 42,477,296 shares.

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CERTAIN DEFINITIONS

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

We have included below the definitions for certain crude oil and natural gas terms used in this report:

“3-D seismic” Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

“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.

“CO_2 flood” A tertiary recovery method in which CO_2 is injected into the reservoir to enhance oil recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“Mbbl/d” One thousand barrels of oil or other liquid hydrocarbons per day.

“MBOE/d” One thousand BOE per day.

“Mcf” One thousand cubic feet of natural gas.

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

“MMBOE” One million BOE.

“MMbtu” One million British Thermal Units.

“MMcf/d” One million cubic feet per day.

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"*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.

"*reservoir*" A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"*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 to share in production, subject to all royalties, overriding royalties and other burdens and to share in all costs of exploration, development and operations and all risks in connection therewith.

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PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

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

	June 30, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,890	$ 10,372
Accounts receivable trade, net	97,280	97,831
Deferred income taxes	5,614	3,025
Prepaid expenses and other	12,267	10,484
Total current assets	123,051	121,712
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	3,052,365	2,828,282
Unproved properties	57,928	55,297
Other property and equipment	39,082	44,902
Total property and equipment	3,149,375	2,928,481
Less accumulated depreciation, depletion and amortization	(567,072)	(495,820)
Oil and gas properties held for sale, net	11,278	-
Total property and equipment, net	2,593,581	2,432,661
DEBT ISSUANCE COSTS	17,123	19,352
OTHER LONG-TERM ASSETS	12,725	11,678
TOTAL	$ 2,746,480	$ 2,585,403

See notes to condensed consolidated financial statements.

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

	June 30, 2007	December 31, 2006
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 23,695	$ 21,077
Accrued liabilities	64,488	58,504
Accrued interest	9,328	9,124
Oil and gas sales payable	20,317	19,064
Accrued employee compensation and benefits	8,436	17,800
Production taxes payable	10,102	9,820
Current portion of tax sharing liability	3,565	3,565
Current portion of derivative liability	11,248	4,088
Total current liabilities	151,179	143,042
NON-CURRENT LIABILITIES:		
Long-term debt	1,084,867	995,396
Asset retirement obligations	40,078	36,982
Production Participation Plan liability	29,593	25,443
Tax sharing liability	24,368	23,607
Deferred income taxes	183,476	165,031
Long-term derivative liability	6,893	5,248
Other long-term liabilities	5,228	3,984
Liabilities associated with oil and gas properties held for sale	996	-
Total non-current liabilities	1,375,499	1,255,691
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 37,053,021 and 36,947,681 shares issued and outstanding as of June 30, 2007 and December 31, 2006, respectively	37	37
Additional paid-in capital	756,236	754,788
Accumulated other comprehensive loss	(11,032)	(5,902)
Retained earnings	474,561	437,747
Total stockholders' equity	1,219,802	1,186,670
TOTAL	$ 2,746,480	$ 2,585,403

See notes to condensed consolidated financial statements.

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 192,646	$ 203,643	$ 352,359	$ 393,509
Gain (loss) on oil and natural gas hedging activities	-	40	-	(9,484)
Interest income and other	258	338	467	627
Total revenues and other income	192,904	204,021	352,826	384,652
COSTS AND EXPENSES:				
Lease operating	51,983	44,657	101,037	89,052
Production taxes	12,079	12,394	21,690	24,330
Depreciation, depletion and amortization	49,335	38,909	93,906	74,209
Exploration and impairment	6,643	9,214	15,820	16,256
General and administrative	8,876	9,638	17,161	19,249
Change in Production Participation Plan liability	2,058	2,069	4,150	4,144
Interest expense	20,754	18,627	40,253	35,601
Unrealized derivative (gain) loss	(423)	-	691	-
Total costs and expenses	151,305	135,508	294,708	262,841
INCOME BEFORE INCOME TAXES	41,599	68,513	58,118	121,811
INCOME TAX EXPENSE:				
Current	1,515	2,581	2,141	4,612
Deferred	13,613	20,052	18,840	38,328
Total income tax expense	15,128	22,633	20,981	42,940
NET INCOME	$ 26,471	$ 45,880	$ 37,137	$ 78,871
NET INCOME PER COMMON SHARE, BASIC	$ 0.72	$ 1.25	$ 1.01	$ 2.15
NET INCOME PER COMMON SHARE, DILUTED	$ 0.72	$ 1.25	$ 1.01	$ 2.14
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	36,808	36,748	36,789	36,737
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	36,905	36,812	36,936	36,783

See notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 37,137	$ 78,871
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	93,906	74,209
Deferred income taxes	18,840	38,328
Amortization of debt issuance costs and debt discount	2,542	2,632
Accretion of tax sharing liability	761	1,050
Stock-based compensation	2,378	1,854
Unproved leasehold impairments	4,642	713
Change in Production Participation Plan liability	4,150	4,144
Unrealized derivative loss	691	-
Other non-current	(1,984)	(1,685)
Changes in current assets and liabilities:		
Accounts receivable trade	551	8,911
Prepaid expenses and other	(1,783)	(3,552)
Accounts payable and accrued liabilities	(3,027)	15,860
Accrued interest	204	(2,928)
Other current liabilities	(9,055)	838
Net cash provided by operating activities	149,953	219,245
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(13,624)	(28,557)
Drilling and development capital expenditures	(230,396)	(239,154)
Proceeds from sale of oil and gas properties	1,291	-
Net cash used in investing activities	(242,729)	(267,711)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings under credit agreement	190,000	120,000
Repayments of long-term borrowings under credit agreement	(100,000)	(70,000)
Debt issuance costs	-	(103)
Tax effect from restricted stock vesting	294	260
Net cash provided by financing activities	90,294	50,157
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,482)	1,691
CASH AND CASH EQUIVALENTS:		
Beginning of period	10,372	10,382
End of period	$ 7,890	$ 12,073
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for income taxes	$ 1,743	$ 3,637
Cash paid for interest	$ 37,809	$ 35,052
NONCASH INVESTING ACTIVITIES:		
(Increase) decrease in accrued capital expenditures	$ (11,545)	$ 4,793

See notes to condensed consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Total Stockholders' Equity	Comprehensive Income
BALANCES—January 1, 2006	36,842	$ 37	$ 753,093	$ (34,620)	$ (2,031)	$ 281,383	$ 997,862	
Net income	-	-	-	-	-	156,364	156,364	$ 156,364
Change in derivative fair values, net of taxes of $15,409	-	-	-	24,140	-	-	24,140	24,140
Realized loss on settled derivative contracts, net of taxes of $2,923	-	-	-	4,578	-	-	4,578	4,578
Restricted stock issued	126	-	-	-	-	-	-	-
Restricted stock forfeited	(10)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(10)	-	(440)	-	-	-	(440)	-
Tax effect from restricted stock vesting	-	-	288	-	-	-	288	-
Adoption of SFAS 123R	-	-	(2,122)	-	2,031	-	(91)	-
Stock-based compensation	-	-	3,969	-	-	-	3,969	-
BALANCES—December 31, 2006	36,948	37	754,788	(5,902)	-	437,747	1,186,670	$ 185,082
Net income	-	-	-	-	-	37,137	37,137	37,137
Change in derivative fair values, net of taxes of $3,394	-	-	-	(5,834)	-	-	(5,834)	(5,834)
Unrealized derivative loss, net of taxes of $410	-	-	-	704	-	-	704	704
Restricted stock issued	144	-	-	-	-	-	-	-
Restricted stock forfeited	(12)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(27)	-	(1,224)	-	-	-	(1,224)	-
Tax effect from restricted stock vesting	-	-	294	-	-	-	294	-
Stock-based compensation	-	-	2,378	-	-	-	2,378	-
Adoption of FIN 48	-	-	-	-	-	(323)	(323)	-
BALANCES—June 30, 2007	37,053	$ 37	$ 756,236	$ (11,032)	$ -	$ 474,561	$ 1,219,802	$ 32,007

See notes to condensed consolidated financial statements.

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WHITING PETROLEUM CORPORATION
NOTES TO CONDENSED 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 subsidiaries.

Consolidated Financial Statements—The unaudited condensed consolidated financial statements include the accounts of Whiting Petroleum Corporation and its subsidiaries, all of which are wholly owned. The financial statements have been prepared in accordance with U.S. generally accepted accounting principles for interim financial reporting. All intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all material adjustments considered necessary for a fair presentation of the Company's interim results have been reflected. Whiting's 2006 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. Except as disclosed herein, there has been no material change to the information disclosed in the notes to consolidated financial statements included in Whiting's 2006 Annual Report on Form 10-K. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Earnings Per Share—Basic net income per common share of stock is calculated by dividing net income by the weighted average number of common shares outstanding during each period. Diluted net income per common share of stock is calculated by dividing net income by the weighted average number of common shares and other dilutive securities outstanding. The only securities considered dilutive are the Company's unvested restricted stock awards.

Reclassifications—Certain prior period balances were reclassified to conform to the current year presentation, and such reclassifications had no impact on net income or stockholders' equity previously reported.

Change in Accounting Principle—In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an interpretation of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("FIN 48"). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

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The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings and a corresponding increase in other long-term liabilities. As of the adoption date and after the impact of recognizing the increase in liability noted above, the Company's unrecognized tax benefits totaled $0.4 million, and there were no additions or reductions to the Company's unrecognized tax benefits during the six months ended June 30, 2007. Included in the balance at January 1, 2007, were $0.1 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. It is reasonably possible that unrecognized tax benefits in the amount of $0.3 million relating to gas imbalances will decrease within the next 12 months, as Whiting is in the process of applying for a change in the method of accounting to a method prescribed by the Internal Revenue Service ("IRS").

The Company files income tax returns in the U.S. Federal jurisdiction, in various states, and previously filed in two foreign jurisdictions. The following is a listing of tax years that remain subject to examination by major jurisdiction:

U.S. Federal	11/23/2003 – 12/31/2006
U.S. states	11/23/2003 – 12/31/2006
Canada	01/01/2002 – 12/31/2006
Province of Alberta	01/01/2002 – 12/31/2006

Prior to November 23, 2003, Whiting was owned 100% by Alliant Energy Corporation ("Alliant Energy"). Alliant Energy is presently under audit by the IRS for the years 1999 through 2003. Based on discussions with Alliant Energy, the Company believes that there are no issues that would require adjustment to Whiting's tax liability for the periods 1999 to 2001. Information is not yet available for the 2002 to 2003 periods.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the six months ended June 30, 2007, the Company did not recognize any interest or penalties in the condensed consolidated statements of income, nor did the Company have any interest or penalties accrued in its condensed consolidated balance sheet at June 30, 2007 relating to unrecognized tax benefits.

2. ACQUISITIONS AND DIVESTITURES

2007 Acquisitions

There were no significant acquisitions during the first six months of 2007.

2006 Acquisitions

Utah Hingeline**—**On August 29, 2006, the Company acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. As part of this transaction, the operator agreed to pay 100% of the Company's drilling and completion costs for the first three wells in the project. The first of these three wells was drilled in the fourth quarter of 2006 but did not find commercial quantities of hydrocarbons. With respect to the remaining two wells, one is planned to be drilled during the remainder of 2007, and the other before the end of 2008.

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Michigan Properties—On August 15, 2006, the Company acquired 65 producing properties, a gathering line, gas processing plant and 30,437 net acres of leasehold held by production in Michigan. The purchase price was $26.0 million for estimated proved reserves of 1.4 MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily production from the properties was 0.6 MBOE/d as of the acquisition effective date. The Company operates 85% of the properties acquired.

The Company funded its 2006 acquisitions with cash on hand as well as through borrowings under its credit agreement.

2006 Divestitures

During 2006, the Company sold its interests in several non-core properties for an aggregate amount of $24.4 million in cash, which consisted of total estimated proved reserves of 1.4 MMBOE as of the divestitures' effective dates. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The average net production from the divested property interests was 0.4 MBOE/d as of the dates of disposition, and the Company recognized a pre-tax gain of $12.1 million in the fourth quarter of 2006 on the sale of these properties.

3. LONG-TERM DEBT

Long-term debt consisted of the following at June 30, 2007 and December 31, 2006 (in thousands):

	June 30, 2007	December 31, 2006
Credit Agreement	$ 470,000	$ 380,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,191 and $2,424, respectively	217,809	217,576
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $610 and $687, respectively	147,058	147,820
Total debt	$ 1,084,867	$ 995,396

Credit Agreement—The Company's wholly-owned subsidiary, Whiting Oil and Gas Corporation ("Whiting Oil and Gas") has a $1.2 billion credit agreement with a syndicate of banks that, as of June 30, 2007, had a borrowing base of $875.0 million. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement. As of June 30, 2007, the outstanding principal balance under the credit agreement was $470.0 million.

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The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the five-year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company in an aggregate amount not to exceed $50.0 million. As of June 30, 2007, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues at Whiting Oil and Gas' option at either (1) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Whiting Oil and Gas has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense. At June 30, 2007, weighted average interest rate on the outstanding principal balance under the credit agreement was 7.5%.

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders and requires the Company to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and Whiting Petroleum Corporation's wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes, or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. The Company was in compliance with its covenants under the credit agreement as of June 30, 2007. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged all of its properties, that are included in the borrowing base for the credit agreement, as security for its guarantee.

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Senior Subordinated Notes—In October 2005, the Company issued $250.0 million of 7% Senior Subordinated Notes due 2014 at par. The estimated fair value of these notes was $234.1 million as of June 30, 2007.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of $3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.5%. The estimated fair value of these notes was $207.9 million as of June 30, 2007.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of $1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $141.8 million as of June 30, 2007.

The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company's ability to, among other things, pay cash dividends, redeem or repurchase the Company's capital stock or the Company's subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of the Company's management in certain respects. The Company was in compliance with these covenants as of June 30, 2007. Three of the Company's wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (the "Guarantors"), have fully, unconditionally, jointly and severally guaranteed the Company's obligations under the notes. The Company does not have any subsidiaries other than the Guarantors, minor or otherwise, within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75.0 million of its 7.25% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that the Company receives the fixed rate of 7.25% and pays the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus the Company's margin of 2.345% is less than 7.25%, the Company receives a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus the Company's margin of 2.345% is greater than 7.25%, the Company pays the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. As of June 30, 2007, the Company has recorded a long-term liability of $2.3 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting reduction in the fair value of the 7.25% Senior Subordinated Notes due 2012.

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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 state and federal laws. The Company determines asset retirement obligations by calculating the present value of estimated cash flows related to plug and abandonment obligations. The following table provides a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2007 (in thousands):

Asset retirement obligation, January 1, 2007	$ 37,534
Additional liability incurred	863
Revisions in estimated cash flows	3,160
Accretion expense	1,354
Obligations on sold properties	(185)
Liabilities settled	(1,016)
Asset retirement obligation, June 30, 2007	$ 41,710

5. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting enters into derivative contracts, primarily costless collars, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. 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 instruments for speculative or trading purposes.

At June 30, 2007, accumulated other comprehensive loss consisted of $17.5 million ($11.0 million after tax) of unrealized losses, representing the mark-to-market value of the Company's open commodity contracts, designated as cash flow hedges, as of the balance sheet date. For the three and six months ended June 30, 2007, Whiting recognized no realized gains or losses on commodity derivative settlements. For the three and six months ended June 30, 2006, Whiting recognized realized cash settlement gains of $0.04 million and realized cash settlement losses of $9.5 million, respectively, on commodity derivative settlements. Based on the estimated fair value of the Company's derivative contracts at June 30, 2007, it expects to reclassify net losses of $10.6 million into earnings related to derivative contracts during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially. The Company has hedged 2.5 MMBbl of crude oil volumes through 2007 and 3.0 MMBbl of crude oil volumes through 2008.

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During the first quarter of 2007, the Company determined that the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring within the specified time periods from April to December of 2007. The Company therefore reclassified the net losses attributable to these hedges out of accumulated other comprehensive loss and recognized $1.1 million in unrealized derivative losses in the condensed consolidated statements of income in the first quarter of 2007, which losses were partially offset by $0.4 million in unrealized mark-to-market derivative gains in the second quarter of 2007. The Company has discontinued hedge accounting prospectively for these collars.

The Company has also entered into an interest rate swap designated as a fair value hedge as further explained in Long-Term Debt.

6. STOCKHOLDERS' EQUITY

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan, pursuant to which two million shares of the Company's common stock have been reserved for issuance. No employee participant may be granted options for more than 300,000 shares of common stock, stock appreciation rights with respect to more than 300,000 shares of common stock or more than 150,000 shares of restricted stock during any calendar year.

Restricted stock awards for executive officers, directors and employees generally vest ratably over three years. In February 2007, however, restricted stock awards granted to executive officers included certain performance conditions, in addition to the standard three-year service condition, that must be met in order for the stock awards to vest. The Company believes that it is probable that such performance conditions will be achieved and has accrued compensation cost accordingly for its 2007 restricted stock grants to executives.

The following table shows a summary of the Company's nonvested restricted stock as of June 30, 2007 as well as activity during the six months then ended (share and per share data, not presented in thousands):

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2007	203,264	$ 39.33
Granted	143,566	$ 45.38
Vested	(90,711)	$ 36.50
Forfeited	(11,269)	$ 44.21
Restricted stock awards nonvested, June 30, 2007	244,850	$ 43.70

The grant date fair value of restricted stock is determined based on the closing bid price of the Company's common stock on the grant date. The Company uses historical data and projections to estimate expected employee behaviors related to restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost.

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As of June 30, 2007, there was $5.7 million of total unrecognized compensation cost related to unvested restricted stock granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 2.0 years. Included within general and administrative and exploration expenses is non-cash stock based compensation related to restricted stock awards of $2.4 million and $1.9 million for the six months ended June 30, 2007 and 2006, respectively, and $1.3 million and $1.1 million for the three months ended June 30, 2007 and 2006, respectively.

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

7. EMPLOYEE BENEFIT PLANS

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

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the six months ended June 30, 2007 and 2006 amounted to $5.9 million and $6.6 million, respectively, charged to general and administrative expense and $1.0 million and $1.2 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, (1) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (2) employees will become fully vested at age 65, regardless of when their interests would otherwise vest; and (3) any forfeitures for Plan years after 2003 inure to the benefit of the Company.

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The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At June 30, 2007, the Company used five-year average historical NYMEX prices of $49.97 for crude oil and $6.36 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control (as defined in the Plan), all employees fully vest and the Company would distribute to each Plan participant an amount based upon the valuation method set forth in the Plan in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on prices at June 30, 2007, 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 $83.7 million. This amount includes $13.4 million attributable to proved undeveloped oil and gas properties and $6.9 million relating to the short-term portion of the Production Participation Plan liability, which has been accrued as a current payable for 2007 plan-year payments owed to employees. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan. The following table presents changes in the estimated long-term liability related to the Plan for the six months ended June 30, 2007 (in thousands):

Production Participation Plan liability, January 1, 2007	$	25,443
Change in liability for accretion, vesting and change in estimate		11,039
Reduction in liability for cash payments accrued and recognized as compensation expense		(6,889)
Production Participation Plan liability, June 30, 2007	$	29,593

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

	Six Months Ended June 30,			
	2007		**2006**	
General and administrative expense	$	3,528	$	3,481
Exploration expense		622		663
Total	$	4,150	$	4,144

401(k) Plan - The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. Employer contributions vest ratably at 20% per year over a five year period.

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8. RELATED PARTY TRANSACTIONS

Prior to Whiting's initial public offering in November 2003, it was a wholly owned indirect subsidiary of Alliant Energy, a holding company whose primary businesses are utility companies. When the transactions discussed below were entered into, Alliant Energy was a related party of the Company. As of December 31, 2004 and thereafter, Alliant Energy was not a related party.

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

Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing the Company's actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting will be obligated to pay Alliant Energy the present value of the remaining tax benefits, assuming all such tax benefits will be realized in future years. The Company has estimated total payments to Alliant will approximate $38.6 million on an undiscounted basis, with a present value of $26.6 million.

During the first six months of 2007, the Company did not make any payments under this agreement but did recognize $0.8 million of accretion expense, which is included as a component of interest expense. The Company's estimated payment of $3.6 million to be made in 2007 under this agreement is reflected as a current liability at June 30, 2007.

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

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

Receivable from Alliant Energy—Prior to the Company's initial public offering, the Company was included in the consolidated federal income tax return of Alliant Energy and calculated its income tax expense on a separate return basis at Alliant Energy's effective tax rate less any research or Section 29 tax credits generated by the Company. Current tax due under this calculation was paid to Alliant Energy, and current refunds were received from Alliant Energy. Section 29 tax credits were generated in 2002 and are expected to be utilized by Alliant Energy in 2007. However, on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. The Company expects to be paid during 2007 for the Section 29 credits, which is when Alliant Energy expects to receive the benefit for them. The Company has a current receivable in the amount of $4.1 million as of June 30, 2007 for these credits.

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

9. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010 and an additional 26,500 square feet of office space in Midland, Texas through February 15, 2012. Rental expense for the first six months of 2007 and 2006 was $1.1 million and $1.0 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of June 30, 2007 are as follows (in thousands):

2007	$	970
2008		1,952
2009		1,965
2010		1,701
2011		329
Thereafter		41
Total	$	6,958

Purchase Contract—The Company has entered into two take-or-pay purchase agreements, one agreement in July 2005 for 9.5 years and one agreement in March 2006 for 8 years, whereby the Company has committed to buy certain volumes of CO_2 for a fixed fee subject to annual escalation. The purchase agreements are with different suppliers, and the CO_2 is for use in enhanced recovery projects in the Postle field in Texas County, Oklahoma and the North Ward Estes field in Ward County, Texas. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO_2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when delivery was to have occurred. The CO_2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, the Company expects to avoid any payments for deficiencies. As of June 30, 2007, future commitments under the purchase agreements amounted to $299.9 million through 2014.

Drilling Contracts—We currently have two drilling rigs under contract through 2007, one drilling rig through 2009 and one drilling rig through 2010, in addition to a workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of June 30, 2007, these agreements had total commitments of $52.1 million and early termination would require maximum penalties of $38.9 million. Other drilling rigs working for the Company are not under long-term contracts but instead are under contracts that can be terminated at the end of the well that is currently being drilled.

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

10. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("SFAS 157"). The adoption of SFAS 157 is not expected to have a material impact on the Company's consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop certain fair value measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

11. SUBSEQUENT EVENTS

On July 3, 2007, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 5,000,000 shares of common stock at a price of $40.50 per share, providing net proceeds of $193.9 million after underwriters' discount and estimated offering expenses. Pursuant to the exercise of the underwriters' overallotment option, the Company sold an additional 425,000 shares of common stock on July 11, 2007, at $40.50 per share, providing net proceeds of $16.5 million. The Company used the net proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. The Company plans to use the increased borrowing capacity available under its credit agreement to finance the drilling and completion of wells and the construction of processing facilities, primarily at the Boies Ranch and Jimmy Gulch prospect areas in the Piceance Basin and at the Robinson Lake prospect area in the Williston Basin. Had the common stock issuance occurred at the beginning of the second quarter of 2007, the number of shares used in the computations of earnings per share would have been 42,233,171 and 39,516,970 for the three and six months ended June 30, 2007, respectively.

On July 17, 2007, the Company sold its approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.8 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, adjusted to the July 1, 2007 divestiture effective date, thereby yielding a sale price of $17.77 per BOE. Our March 2007 average daily production from these fields was 745 BOE/d.

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The divested properties' carrying amounts and corresponding major classes of assets and liabilities classified as "held for sale" in the condensed consolidated balance sheet as of June 30, 2007 are as follows (in thousands):

Proved properties	$	28,122
Accumulated depreciation, depletion and amortization	$	16,844
Asset retirement obligations	$	996

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

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

Overview

We are an independent oil and gas company engaged in oil and gas acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. During 2004 and 2005, we emphasized the acquisition of properties that provided additional volumes to our current production levels as well as upside potential through further development. During 2006 and the first half of 2007, we have focused our drilling activity on the development of these acquired properties, specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and subsequent development allows us to direct our capital resources to what we believe to be the most advantageous investments.

While historically we have grown through acquisitions, we are increasingly focused on a balanced exploration and development program while selectively pursuing acquisitions. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

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

We have historically acquired operated and non-operated properties that meet or 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 sale price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

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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. Sustained periods of low prices for oil or gas could materially and adversely affect our financial position, results of operations, cash flows, access to capital, and the quantities of oil and gas reserves that we can economically produce.

Second Quarter 2007 Highlights

On May 22, 2007, we initiated a CO2 flood in the North Ward Estes field, located in Ward and Winkler Counties, Texas. We are injecting into the field's producing reservoir, the Yates formation, at a depth of 2,600 feet. Our target for CO2 injection into the field is 100 MMcf/d by the end of January 2008.

The Boies B-19N-N3 discovery well, located in the Piceance Basin, was completed flowing 2.5 MMcf/d. The Boies Ranch prospect is located in Rio Blanco County, Colorado. We are the operator of this discovery well, and hold a 50% working interest and a 49% net revenue interest in this well. Subsequent to the completion of the discovery well, we drilled and completed two additional gas producers at Boies Ranch, with each well flowing at an initial rate of approximately 2.3 MMcf/d.

The Peery State 11-25H discovery well, located in the Williston Basin, was completed with an initial flow rate of 1.1 Mbbl/d and 1.0 MMcf/d. The Robinson Lake prospect is located in Mountrail County, North Dakota. We hold a 99% working interest (80% net revenue interest) in the discovery well and are the operator. As of June 30, 2007, the Peery State 11-25H was producing at an average daily rate of approximately 640 BOE per day.

Immediately east of the Robinson Lake prospect is the Parshall field. We own 63,000 gross (13,000 net) acres in the Parshall field, where we have participated in 14 wells. The initial five were completed between June 2006 and June 2007 and had average initial production rates of 1.3 MBOE/d. The other nine wells are currently being drilled or undergoing completion operations. We hold an average 19% working interest in the non-operated Parshall field.

Events and Operations for the Remainder of 2007

On July 3, 2007, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 5,000,000 shares of common stock at a price of $40.50 per share, providing net proceeds of $193.9 million after estimated expenses. Pursuant to the exercise of the underwriters' overallotment option, the Company sold an additional 425,000 shares of common stock on July 11, 2007, at $40.50 per share, providing net proceeds of $16.5 million. The Company used the net proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement, thereby increasing the borrowing capacity available under the credit agreement.

On July 17, 2007, we sold our approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.8 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, adjusted to the July 1, 2007 divestiture effective date, resulting in a sale price of $17.77 per BOE. Our March 2007 average daily production from these fields was 745 BOE/d.

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We intend to accelerate drilling in our Boies Ranch and Jimmy Gulch prospect areas in the Piceance Basin and our Robinson Lake area in the Williston Basin, two exploratory areas where initial drilling results have been encouraging. We expect net capital investment in drilling and completion of wells and construction of processing facilities in these areas during the remainder of 2007 through 2009 to total $335.8 million. We anticipate funding this investment with the increased borrowing capacity available under our credit agreement, as well as incremental cash flows generated by these capital investments.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which has resulted in reserve and production increases. As we intend to continue to invest in these projects, we have increased our budget for exploration and development in 2007 from $450.0 million to $525.0 million due to additional drilling opportunities that have been identified on these and other of our properties. For 2007, we expect to allocate $200.0 million, or 38% of our $525.0 million exploration and development budget to these two projects.

We have identified additional non-core properties, which had an average lease operating expense per BOE of $25.93 in 2006, that we plan to sell through auctions during 2007. These properties had estimated proved reserves of 1.1 MMBOE as of December 31, 2006, adjusted to an October 1, 2007 effective date. Our March 2007 average daily production from these properties was 473 BOE/d. We are also evaluating and engaged in discussions with respect to the potential sale of economic interests in other non-core properties, although we have not made a decision on whether to do so or the form that any such transaction would take. Our intention is to monetize the value of some of our predominantly proved developed producing properties with this potential sale. These property interests had estimated reserves of up to 8.6 MMBOE as of December 31, 2006, adjusted to an August 1, 2007 effective date. These properties represent up to 3.5% of our proved reserves as of December 31, 2006 and 9.5%, or 3,738 BOE/d, of our March 2007 average daily production. We expect to use the net proceeds from these asset sales to repay debt under our credit agreement. We cannot provide any assurance, however, that we will be able to complete these asset sales.

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Results of Operations

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Selected Operating Data:	Six Months Ended June 30, 2007		Six Months Ended June 30, 2006	
Net production:				
Oil (MMbls)		4.6		4.8
Natural gas (Bcf)		15.8		16.0
Total production (MMBOE)		7.3		7.5
Net sales (in millions):				
Oil(1)	$	247.4	$	279.8
Natural gas(1)		105.0		113.7
Total oil and natural gas sales	$	352.4	$	393.5
Average sales prices:				
Oil (per Bbl)	$	53.48	$	58.16
Effect of oil hedges on average price (per Bbl)		-		(1.86)
Oil net of hedging (per Bbl)	$	53.48	$	56.30
Average NYMEX price	$	61.59	$	67.14
Natural gas (per Mcf)	$	6.65	$	7.13
Effect of natural gas hedges on average price (per Mcf)		-		(0.03)
Natural gas net of hedging (per Mcf)	$	6.65	$	7.10
Average NYMEX price	$	7.16	$	7.91
Cost and expense (per BOE):				
Lease operating expenses	$	13.92	$	11.92
Production taxes	$	2.99	$	3.26
Depreciation, depletion and amortization expense	$	12.94	$	9.94
General and administrative expenses	$	2.36	$	2.58

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $41.1 million to $352.4 million in the first six months of 2007 compared to the first six months of 2006. Sales are a function of volumes sold and average sales prices. Our oil sales volumes decreased 4%, and our gas sales volumes decreased 1% between periods**.** The volume declines resulted in part from production shut-ins due to a fire at a third-party refinery and also from normal field production decline, which was largely offset by production increases from development activities. As a result of the refinery fire, approximately 34,000 BOE of production from the Postle field was shut-in or restricted from February 19 through March 8, 2007. In addition, the decrease in production resulted from a fewer number of production wells being drilled and the conversion of some production wells to injectors at our North Ward Estes field, as the reservoir was pressured up in the Phase 1 area in preparation for CO_2 injection. Our average price for oil before effects of hedging decreased 8% and our average price for natural gas before effects of hedging decreased 7% between periods.

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Gain (Loss) on Oil and Natural Gas Hedging Activities. We hedged 56% of our oil volumes during the first six months of 2007, incurring no realized hedging gains or losses, and 54% of our oil volumes during the first six months of 2006, incurring derivative settlement losses of $9.0 million. We hedged 30% of our gas volumes during the first six months of 2007, incurring no realized hedging gains or losses and 58% of our gas volumes during the first six months of 2006 incurring derivative settlement losses of $0.5 million. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil hedges as of July 16, 2007.

Lease Operating Expenses. Our lease operating expenses increased $12.0 million to $101.0 million in the first six months of 2007 compared to the first six months of 2006. Our lease operating expense as a percentage of oil and gas sales increased from 23% during the first six months of 2006 to 29% during the first six months of 2007. Our lease operating expenses per BOE increased from $11.92 during the first six months of 2006 to $13.92 during the first six months of 2007. The increase of 17% on a BOE basis was primarily caused by inflation in the cost of oil field goods and services, a high level of workover activity, and a change in labor billing practices. The cost of oil field goods and services increased due to a higher demand in the industry. Workovers amounted to $6.5 million in the first six months of 2007, as compared to $4.1 million of workover activity in the first six months of 2006. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to Council of Petroleum Accountants Societies ("COPAS") guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the first six months of 2007 and 2006 were 6.2% of oil and gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $19.7 million to $93.9 million during the first six months of 2007, as compared to the first six months of 2006. On a BOE basis, our DD&A rate increased from $9.94 during the first six months of 2006 to $12.94 in the first six months of 2007. The primary factors causing this rate increase were (1) additional drilling expenditures incurred during the past 12 months in relation to net oil and gas reserve additions over the same time period, and (2) the amount of expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30,	
	2007	**2006**
Depletion	$ 91,049	$ 71,959
Depreciation	1,503	1,130
Accretion of asset retirement obligations	1,354	1,120
Total	$ 93,906	$ 74,209

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Exploration and Impairment Costs. Our exploration and impairment costs decreased $0.4 million to $15.8 million in the first six months of 2007 compared to the first six months of 2006. The components of exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Exploration	$ 11,178	$ 15,543
Impairment	4,642	713
Total	$ 15,820	$ 16,256

During the first six months of 2007, we did not drill any exploratory dry holes, as compared to the first six months of 2006, during which we drilled two exploratory dry holes in the Rocky Mountains region and one exploratory dry hole in the Gulf Coast region, totaling $5.2 million. This reduction in exploratory dry hole expense was partially offset by a slight increase in geological and geophysical expenses during the first six months of 2007. The impairment charge in 2007 and 2006 is related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of June 30, 2007, the amount of unproved properties being amortized increased by $32.8 million primarily as a result of significant unproved acreage purchases during 2006.

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

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
General and administrative expenses	$ 32,998	$ 29,068
Reimbursements and allocations	(15,837)	(9,819)
General and administrative expense, net	$ 17,161	$ 19,249

General and administrative expense before reimbursements and allocations increased $3.9 million to $33.0 million during the first six months of 2007. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $3.4 million. The increase in reimbursements and allocations in the first six months of 2007 was caused by increased salary expenses and a higher number of field workers on operated properties. In addition during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. These changes in labor billing practices resulted in higher reimbursements and allocations and higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. Our net general and administrative expenses as a percentage of oil and gas sales remained consistent at 5% during the first half of 2007 compared to the first half of 2006.

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Change in Production Participation Plan Liability. For the six months ended June 30, 2007, this non-cash expense was consistent with the first six months of 2006 at $4.2 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2008 under our Production Participation Plan ("Plan"). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. This expense in 2007 and in 2006 primarily reflects changes to future cash flow estimates and related Plan liability due to the effect of a sustained higher price environment, recent acquisitions, and employees' continued vesting in the Plan. During the six months ended June 30, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $3.77 for crude oil and $0.38 for natural gas from December 31, 2006, as compared to increases of $3.45 for crude oil and $0.44 for natural gas for the six months ended June 30, 2006. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

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

	Six Months Ended June 30,	
	2007	**2006**
Credit Agreement	$ 15,440	$ 9,510
Senior Subordinated Notes	22,373	22,172
Amortization of debt issue costs and debt discount	2,542	2,632
Accretion of tax sharing liability	761	1,050
Other	200	443
Capitalized interest	(1,063)	(206)
Total interest expense	$ 40,253	$ 35,601

The increase in interest expense was mainly due to additional borrowings outstanding in 2007 under our credit agreement, which were partially offset by increased capitalized interest related to construction and expansion of processing facilities.

Our weighted average debt outstanding during the first six months of 2007 was $1,060.8 million versus $924.8 million in the first six months of 2006. Our weighted average effective cash interest rate was 7.2% during the first six months of 2007 versus 6.9% during the first six months of 2006. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.6% during the first six months of 2007 versus 7.5% during the first six months of 2006.

Unrealized Derivative Loss. During the first quarter of 2007, we determined that the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring prior to the contracts expiring from April through December of 2007. We therefore reclassified the net losses attributable to these hedges out of accumulated other comprehensive loss and recognized $1.1 million in unrealized derivative losses in the condensed consolidated statements of income in the first quarter of 2007, which losses were partially offset by $0.4 million in unrealized mark-to-market derivative gains in the second quarter of 2007. We discontinued hedge accounting prospectively for these collars. During the first six months of 2006, we did not recognize any unrealized derivative losses.

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Income Tax Expense. Income tax expense totaled $21.0 million for the first six months of 2007 and $42.9 million for the first six months of 2006. Our effective income tax rate increased from 35.3% for the first six months of 2006 to 36.1% for the first six months of 2007. Our effective income tax rate was lower for the six months ended June 30, 2006 due to the recognition of a $2.5 million deferred tax benefit for 2005 enhanced oil recovery ("EOR") tax credits and a deferred tax benefit of $0.7 million, as a result of recent Texas corporate tax legislation and other one-time benefits.

Net Income. Net income decreased from $78.9 million during the first six months of 2006 to $37.1 million during the first six months of 2007. The primary reasons for this decrease included a 3% decrease in equivalent volumes sold, a 5% decrease in oil prices (net of hedging) and a 6% decrease in gas prices (net of hedging) between periods, higher lease operating expense, DD&A, interest expense and unrealized derivative loss. The decreased production and pricing and increased expenses were partially offset by lower production taxes, exploration and impairment and general and administrative expenses in the first half of 2007.

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006

Selected Operating Data:	Three Months Ended June 30, 2007	2006
Net production:		
Oil (MMbls)	2.4	2.4
Natural gas (Bcf)	8.1	8.2
Total production (MMBOE)	3.7	3.8
Net sales (in millions):		
Oil(1)	$ 136.6	$ 149.3
Natural gas(1)	56.0	54.3
Total oil and natural gas sales	$ 192.6	$ 203.6
Average sales prices:		
Oil (per Bbl)	$ 57.38	$ 61.22
Effect of oil hedges on average price (per Bbl)	-	-
Oil net of hedging (per Bbl)	$ 57.38	$ 61.22
Average NYMEX price	$ 65.02	$ 70.70
Natural gas (per Mcf)	$ 6.95	$ 6.66
Effect of natural gas hedges on average price (per Mcf)	-	-
Natural gas net of hedging (per Mcf)	$ 6.95	$ 6.66
Average NYMEX price	$ 7.55	$ 6.80
Cost and expense (per BOE):		
Lease operating expenses	$ 13.96	$ 11.76
Production taxes	$ 3.24	$ 3.26
Depreciation, depletion and amortization expense	$ 13.25	$ 10.24
General and administrative expenses	$ 2.38	$ 2.54

(1) Before consideration of hedging transactions.

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Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $11.0 million to $192.6 million in the second quarter of 2007 compared to the second quarter of 2006. Sales are a function of volumes sold and average sales prices. Our oil sales volumes remained consistent between quarters, and our gas sales volumes decreased 1% between periods. The volume decline resulted primarily from normal field production decline, which was almost entirely offset by production increases from development activities. In addition, the decrease in production resulted from a fewer number of production wells being drilled and the conversion of some production wells to injectors at our North Ward Estes field, as the reservoir was pressured up in the Phase 1 area in preparation for CO_2 injection. Our average price for oil before effects of hedging decreased 6% and our average price for natural gas before effects of hedging increased 4% between periods.

Lease Operating Expenses. Our lease operating expenses increased $7.3 million to $52.0 million in the second quarter of 2007 compared to the second quarter of 2006. Our lease operating expense as a percentage of oil and gas sales increased from 22% during the second quarter of 2006 to 27% during the second quarter of 2007. Our lease operating expenses per BOE increased from $11.76 during the second quarter of 2006 to $13.96 during the second quarter of 2007. The increase of 19% on a BOE basis was primarily caused by inflation in the cost of oil field goods and services, a high level of workover activity, and a change in labor billing practices. The cost of oil field goods and services increased due to a higher demand in the industry. Workovers amounted to $3.6 million in the second quarter of 2007, as compared to $1.8 million of workover activity in the second quarter of 2006. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the second quarter of 2007 and 2006 were 6.3% and 6.1%, respectively, of oil and gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $10.4 million to $49.3 million during the second quarter of 2007, as compared to the second quarter of 2006. On a BOE basis, our DD&A rate increased from $10.24 during the second quarter of 2006 to $13.25 in the second quarter of 2007. The primary factors causing this rate increase were (1) additional drilling expenditures incurred during the past 12 months in relation to net oil and gas reserve additions over the same time period, and (2) the amount of expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30,	
	2007	**2006**
Depletion	$ 47,825	$ 37,738
Depreciation	763	599
Accretion of asset retirement obligations	747	572
Total	$ 49,335	$ 38,909

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Exploration and Impairment Costs. Our exploration and impairment costs decreased $2.6 million to $6.6 million in the second quarter of 2007 compared to the second quarter of 2006. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended June 30,			
	2007		2006	
Exploration	$	4,318	$	8,642
Impairment		2,325		572
Total	$	6,643	$	9,214

During the second quarter of 2007, we did not drill any exploratory dry holes, as compared to the second quarter of 2006, during which we drilled two exploratory dry holes in the Rocky Mountains region totaling $2.4 million. The impairment charge in 2007 and 2006 is related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of June 30, 2007, the amount of unproved properties being amortized increased by $32.8 million primarily as a result of significant unproved acreage purchases during 2006.

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

	Three Months Ended June 30,			
	2007		2006	
General and administrative expenses	$	17,155	$	14,948
Reimbursements and allocations		(8,279)		(5,310)
General and administrative expense, net	$	8,876	$	9,638

General and administrative expense before reimbursements and allocations increased $2.2 million to $17.2 million during the second quarter of 2007. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $1.8 million. The increase in reimbursements and allocations in the second quarter of 2007 was caused by increased salary expenses and a higher number of field workers on operated properties. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. These changes in labor billing practices resulted in higher reimbursements and allocations to us and higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. Our general and administrative expenses as a percentage of oil and gas sales remained constant at 5% during the three months ended June 30, 2007 compared to the same period in 2006.

Change in Production Participation Plan Liability. For the three months ended June 30, 2007, this non-cash expense was consistent with the same quarter in 2006 at $2.1 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2008 under our Production Participation Plan ("Plan"). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. This expense in 2007 and in 2006 primarily reflects changes to future cash flow estimates and related Plan liability due to the effect of a sustained higher price environment, recent acquisitions, and employees' continued vesting in the Plan.

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During the three months ended June 30, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $1.72 for crude oil and $0.08 for natural gas from March 31, 2007, as compared to increases of $2.20 for crude oil and $0.15 for natural gas for the three months ended June 30, 2006. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

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

	Three months Ended June 30, 2007	Three months Ended June 30, 2006
Credit Agreement	$ 8,417	$ 5,393
Senior Subordinated Notes	11,192	11,163
Amortization of debt issue costs and debt discount	1,265	1,309
Accretion of tax sharing liability	381	525
Other	100	443
Capitalized interest	(601)	(206)
Total interest expense	$ 20,754	$ 18,627

The increase in interest expense was mainly due to additional borrowings outstanding in 2007 under our credit agreement, which were partially offset by increased capitalized interest related to construction and expansion of processing facilities.

Our weighted average debt outstanding during the second quarter of 2007 was $1,091.3 million versus $947.5 million in the second quarter of 2006. Our weighted average effective cash interest rate was 7.2% during the second quarter of 2007 and 2006. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.6% during the second quarter of 2007 versus 7.7% during the second quarter of 2006.

Unrealized Derivative Loss. During the first quarter of 2007, we determined that the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring prior to the contracts expiring from April through December of 2007. We therefore reclassified the net losses attributable to these hedges out of accumulated other comprehensive loss and recognized $1.1 million in unrealized derivative losses in the condensed consolidated statements of income in the first quarter of 2007, which losses were partially offset by $0.4 million in unrealized mark-to-market derivative gains in the second quarter of 2007. We discontinued hedge accounting prospectively for these collars. During the second quarter of 2006, we did not recognize any unrealized derivative losses.

Income Tax Expense. Income tax expense totaled $15.1 million for the second quarter of 2007 and $22.6 million for the second quarter of 2006. Our effective income tax rate increased from 33.0% for the second quarter of 2006 to 36.4% for the same period in 2007. Our effective income tax rate was lower in the second quarter of 2006 due to the recognition of a $2.5 million deferred tax benefit for 2005 EOR tax credits and a deferred tax benefit of $0.7 million, as a result of recent Texas corporate tax legislation and other one-time benefits.

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Net Income. Net income decreased from $45.9 million during the second quarter of 2006 to $26.5 million during the second quarter of 2007. This decrease resulted from a 2% decrease in equivalent volumes sold, a 6% decrease in oil prices (net of hedging) offset by a 4% increase in gas prices (net of hedging) between periods, higher lease operating expense, DD&A, and interest expense. The decreased production and pricing and increased expenses were partially offset by lower production taxes, exploration and impairment, general and administrative expenses and an unrealized derivative gain in the second quarter of 2007.

Liquidity and Capital Resources

Overview. At December 31, 2006, our debt to total capitalization ratio was 45.6%, we had $10.4 million of cash on hand and $1,186.7 million of stockholders' equity. At June 30, 2007, our debt to total capitalization ratio was 47.1%, we had $7.9 million of cash on hand and $1,219.8 million of stockholders' equity. Had we received the proceeds from our common stock issuance, net of underwriters' discount and estimated offering expenses, and the proceeds from our property sale, both of which occurred in July 2007, and repaid a portion of the debt outstanding under our credit agreement at the end of the second quarter, we would have had a pro forma June 30, 2007 debt to total capitalization ratio of 36.8% and stockholders' equity of $1,430.2 million. In addition, due to this debt repayment subsequent to quarter end, our pro forma weighted average interest rate decreased to 6.7% and our available borrowing capacity under our credit agreement is now approximately $650.0 million.

In the first half of 2007, we generated $150.0 million of cash provided by operating activities, a decrease of $69.3 million over the same period in 2006. Cash provided by operating activities decreased primarily because of lower average sales prices for crude oil and natural gas, slightly lower production volumes and higher cash lease operating expenses. We also generated $90.3 million from financing activities primarily consisting of $90.0 million in net borrowings under our credit agreement. Cash on hand and cash flows from operating and financing activities were primarily used to finance $241.6 million of exploration and development expenditures paid in the first half of 2007 and $16.7 million of cash acquisition capital expenditures to acquire the Parshall Prospect in North Dakota. The chart below details our exploration and development expenditures incurred by region during the first half of 2007 (in thousands).

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Permian Basin	$ 83,035	$ 2,291	$ 85,326	34%
Rocky Mountains	70,621	6,155	76,776	30%
Mid-Continent	67,140	1,038	68,178	27%
Gulf Coast	12,733	1,222	13,955	6%
Michigan	8,412	472	8,884	3%
Total incurred	241,941	11,178	253,119	100%
Increase in accrued capital expenditures	(11,545)	-	(11,545)	
Total paid	230,396	11,178	$ 241,574	

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We continually evaluate our capital needs and compare them to our capital resources. Our 2007 budgeted exploration and development expenditures for the further development of our property base are $525.0 million, an increase from the $485.1 million incurred on exploration and development expenditures during 2006. We have increased our budget for exploration and development in 2007 from $450.0 million to $525.0 million due to additional drilling opportunities that have been identified in our Boies Ranch and Jimmy Gulch prospect areas in the Piceance Basin and our Robinson Lake area in the Williston Basin, and other core areas. Although we have no specific budget for property acquisitions in 2007, we will continue to selectively pursue property acquisitions that complement our existing core property base. We expect to fund our 2007 exploration and development expenditures from internally generated cash flow, cash on hand and borrowings under our credit agreement. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed $525.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, or agreements with industry partners. Our level of exploration and development expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future.

Credit Agreement. Our wholly-owned subsidiary, Whiting Oil and Gas Corporation ("Whiting Oil and Gas") has a $1.2 billion credit agreement with a syndicate of banks that, as of June 30, 2007, had a borrowing base of $875.0 million with $470.0 million outstanding, leaving $405.0 million of available borrowing capacity. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to our lenders and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the five-year term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect from at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours in an aggregate amount not to exceed $50.0 million. As of June 30, 2007, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues at Whiting Oil and Gas' option at either (1) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. We have consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage and are included as a component of interest expense. As of June 30, 2007, the effective weighted average interest rate on the outstanding principal balance under the credit agreement was 7.5%.

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The credit agreement contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders and requires us to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and our wholly owned subsidiary, Equity Oil Company, to make any dividends, distributions or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. We were in compliance with our covenants under the credit agreement as of June 30, 2007. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for our guarantee, and Equity Oil Company has mortgaged all of its properties, which are included in the borrowing base for the credit agreement, as security for its guarantee.

Senior Subordinated Notes. In October 2005, we issued $250.0 million of 7% Senior Subordinated Notes due 2014 at par.

In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. The notes were issued at 98.507% of par, and the associated discount is being amortized to interest expense over the term of the notes.

In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. The notes were issued at 99.26% of par, and the associated discount is being amortized to interest expense over the term of the notes.

The notes are unsecured obligations of ours and are subordinated to all of our senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The indentures governing the notes 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, incur additional indebtedness 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, 2007. Three of our wholly-owned operating subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

Shelf Registration Statement. In May 2006, we filed a universal shelf registration statement with the SEC to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may periodically offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

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Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of June 30, 2007 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include Production Participation Plan liabilities since we cannot determine with accuracy the timing of future payment amounts (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)	$ 1,090,000	$ -	$ -	$ 620,000	$ 470,000
Cash interest expense on debt (b)	381,164	77,711	155,423	93,905	54,125
Asset retirement obligation (c)	41,710	636	1,141	3,064	36,869
Tax sharing liability (d)	26,602	3,565	5,988	5,044	12,005
Derivative contract liability fair value (e)	18,141	11,248	6,893	-	-
Purchasing obligations (f)	299,925	33,244	101,765	99,202	65,714
Drilling rig contracts (g)	52,090	23,538	28,552	-	-
Operating leases (h)	6,958	1,945	3,930	1,083	-
Total	$ 1,916,590	$ 151,887	$ 303,692	$ 822,298	$ 638,713

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

(b) Cash interest expense on the 7.25% Senior Subordinated Notes due 2012 and 2013 and the 7% Senior Subordinated Notes due 2014 is estimated assuming no principal repayment until the due date of the instruments. The interest rate swap on the $75.0 million of our $150.0 million fixed rate 7.25% Senior Subordinated Notes due 2012 is assumed to equal 7.7% until the due date of the instrument. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date, and a fixed interest rate of 7.0%.

(c) Asset retirement obligations represent the estimated present value of amounts expected to be incurred to plug, abandon and remediate oil and gas properties.

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

(e) We have entered into derivative contracts, primarily costless collars, to hedge our exposure to crude oil price fluctuations. As of June 30, 2007, the forward price curves for crude oil generally exceeded the price curves that were in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk.

(f) We entered into two take-or-pay purchase agreements, one agreement in July 2005 for 9.5 years and one agreement in March 2006 for 8 years, whereby we have committed to buy certain volumes of CO_2 for a fixed fee, subject to annual escalation, for use in enhanced recovery projects in our Postle field in Texas County, Oklahoma and our North Ward Estes field in Ward County, Texas. The purchase agreements are with different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO_2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. The CO_2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

(g) We currently have two drilling rigs under contract through 2007, one drilling rig through 2009 and one drilling rig through 2010, in addition to a workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of June 30, 2007, early termination of these contracts would have required maximum penalties of $38.9 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the drilling time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

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(h) We lease 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010, and an additional 26,500 square feet of office space in Midland, Texas through February 15, 2012.

Based on current oil and 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 Policies

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an interpretation of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("FIN 48"). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007, balance of retained earnings. The total amount of unrecognized tax benefits as of the adoption date was $0.4 million, and there were no additions or reductions to our unrecognized tax benefits during the six months ended June 30, 2007. Our policy is to recognize interest and penalties accrued related to unrecognized tax benefits within income tax expense.

New Accounting Pronouncements

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("SFAS 157"). The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop the measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

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, 2006.

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Effects of Inflation and Pricing

We experienced increased costs during 2006 and the first half of 2007 due to increased demand for oil field products and services. The oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans 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, continued high prices for oil and 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.

These risks and uncertainties include, but are not limited to: declines in oil or gas prices; 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 drilling rigs and CO_2; our ability to obtain external capital to finance acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses, including our ability to realize cost savings from completed acquisitions; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete our planned and potential asset dispositions; inaccuracies of our reserve estimates or our assumptions underlying them; 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; risks related to our level of indebtedness and periodic redeterminations of our borrowing base under our credit agreement; our ability to replace our oil and 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 Part II, Item 1A of this Quarterly Report on Form 10-Q. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006 and have not materially changed since that report was filed.

Our outstanding hedges as of July 16, 2007 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Crude Oil	07/2007 to 09/2007	110,000	$50.00/$70.90
Crude Oil	07/2007 to 09/2007	300,000	$50.00/$77.55
Crude Oil	10/2007 to 12/2007	110,000	$49.00/$71.50
Crude Oil	10/2007 to 12/2007	300,000	$50.00/$76.50
Crude Oil	01/2008 to 03/2008	110,000	$49.00/$70.65
Crude Oil	01/2008 to 03/2008	120,000	$60.00/$73.90
Crude Oil	01/2008 to 03/2008	100,000	$65.00/$80.30
Crude Oil	04/2008 to 06/2008	110,000	$48.00/$71.60
Crude Oil	04/2008 to 06/2008	120,000	$60.00/$74.65
Crude Oil	04/2008 to 06/2008	100,000	$65.00/$80.50
Crude Oil	07/2008 to 09/2008	110,000	$48.00/$70.85
Crude Oil	07/2008 to 09/2008	120,000	$60.00/$75.60
Crude Oil	07/2008 to 09/2008	100,000	$65.00/$81.00
Crude Oil	10/2008 to 12/2008	110,000	$48.00/$70.20
Crude Oil	10/2008 to 12/2008	120,000	$60.00/$75.85
Crude Oil	10/2008 to 12/2008	100,000	$65.00/$81.20

The crude oil collars 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 beyond the ceiling. For the 2007 crude oil contracts listed above, a hypothetical $1.00 change in the NYMEX price would cause a change in the gain (loss) on hedging activities in 2007 of $2.5 million.

In a 1997 non-operated property acquisition, we became subject to the operator's fixed price gas sales contract with end users for a portion of the natural gas we produce in Michigan. This contract has built-in pricing escalators of 4% per year. Our estimated future production volumes to be sold under the fixed pricing terms of this contract as of July 1, 2007 are summarized below:

Commodity	**Period**	**Monthly Volume (MMBtu)**	**2007 Price Per MMBtu**
Natural Gas	07/2007 to 05/2011	29,000	$4.75
Natural Gas	07/2007 to 09/2012	66,000	$4.21

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Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Vice President and 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, 2007. Based upon their evaluation of these disclosure controls and procedures, the Chairman, President and Chief Executive Officer and the Vice President and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of June 30, 2007 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission’s rules and forms, 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, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II– OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all of the other information contained in this report, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected and you may lose all or part of your investment.

Risks Relating to the Oil and Gas Industry and Our Business

A substantial or extended decline in oil and gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

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

- the price and availability of competitors’ supplies of oil and gas in captive market areas; and
- the price and availability of alternative fuels.

Lower oil and gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and gas that we can produce economically. A substantial or extended decline in oil or gas prices may materially and adversely affect our future business, financial condition, 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.

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

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

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, including drilling rigs, CO_2 and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and storms;
- reductions in oil and gas prices; and
- title problems.

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

We describe some of our current prospects and our plans to explore those prospects in this report and in our Annual Report on Form 10-K for the year ended December 31, 2006. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. The analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

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

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2006, we had identified and scheduled 900 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

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

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO_2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and natural gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

Our acquisition activities may not be successful.

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

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

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

As of December 31, 2006, undeveloped reserves comprised 54% of the North Ward Estes field's total estimated proved reserves and 34% of Postle field's estimated total proved reserves. To fully develop these reserves, we expect to incur future development costs of $639.4 million at the North Ward Estes field and $302.6 million at the Postle field. During 2006, the estimated capital expenditures necessary to develop the proved reserves at the North Ward Estes field and Postle field increased substantially. The increase was due to several factors, including equipment and service cost inflation, higher CO_2 unit costs and volumes, higher costs associated with the expanded scope of previously identified projects as well as new projects identified during 2006. Together, these fields encompass 80% of our estimated total future development costs related to proved reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

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

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

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

Our business strategy includes a continuing acquisition program. From 2004 to 2006, we completed 12 separate acquisitions of producing properties with a combined purchase price of $1,458.8 million for estimated proved reserves as of the effective dates of the acquisitions of 207.7 MMBOE, representing an average cost of $7.02 per BOE of estimated proved reserves. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

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

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

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

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

As of June 30, 2007, we had $470.0 million in outstanding consolidated indebtedness under Whiting Oil and Gas Corporation’s (“Whiting Oil and Gas”) credit agreement with $405.0 million of available borrowing capacity, as well as $620.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas’ credit agreement.

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

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas' credit agreement may be at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas' credit agreement is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our debt under the credit agreement.

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

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

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

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

In addition, Whiting Oil and Gas' credit agreement also requires us to maintain a certain working capital ratio and a certain debt to EBITDAX (as defined in the credit agreement) ratio.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

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

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

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

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

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

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

The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this report.

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

Actual future production, oil and gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2006 would have decreased from $2,392.2 million to $2,382.1 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2006 would have decreased from $2,392.2 million to $2,340.9 million.

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

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

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

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

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

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

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

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

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

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

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

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

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

We intend to accelerate our development in the Piceance Basin. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in the Piceance Basin caused by transportation capacity constraints, curtailment of production or interruption of transportation of natural gas produced from the wells in this basin. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

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

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

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

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

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

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

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and gas industry in general. For instance, in response to studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere, the U.S. Congress is actively considering legislation, and more than a dozen states have already taken legal measures to reduce emission of these gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Moreover, the U.S. Supreme Court only recently held in a case, *Massachusetts, et al. v. EPA* , that greenhouse gases fall within the federal Clean Air Act’s definition of “air pollutant," which could result in the regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our products.

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

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

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

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

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

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

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

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

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

We enter into hedging transactions of our oil and gas production to reduce our exposure to fluctuations in the price of oil and gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of July 16, 2007, we had contracts maturing in 2007 covering the sale of 410,000 barrels of oil per month and contracts maturing throughout 2008 covering the sale of 330,000 barrels of oil per month. As of July 16, 2007, we had no outstanding gas hedges, and all our oil hedges expire by December 2008. Whiting Oil and Gas' credit agreement required us to hedge at least 55% of our total forecasted oil production from the Postle properties and the North Ward Estes properties for the period through December 31, 2008. This hedge requirement was put in place during the third quarter of 2005. See "Quantitative and Qualitative Disclosure about Market Risk" for pricing and a more detailed discussion of our hedging transactions.

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

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

Whiting Petroleum Corporation held its annual meeting of stockholders on May 8, 2007. At such meeting, Thomas L. Aller and Thomas P. Briggs were reelected as directors for terms to expire at the 2010 annual meeting of stockholders and until their successors are duly elected and qualified pursuant to the following votes:

	Shares Voted	
Name of Nominee	**For**	**Withheld**
Thomas L. Aller	26,377,858	7,276,301
Thomas P. Briggs	32,501,962	1,152,197

The other directors of Whiting Petroleum Corporation whose terms of office continued after the 2007 annual meeting of stockholders are as follows: terms expiring at the 2008 annual meeting: Kenneth R. Whiting, Palmer L. Moe and D. Sherwin Artus and terms expiring at the 2009 annual meeting: Graydon D. Hubbard and James J. Volker.

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The following other matter brought for vote at the 2007 annual meeting of stockholders passed by the vote indicated:

	Shares Voted			
	For	**Against**	**Abstain**	**Broker Non-Vote**
Ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm	33,526,055	40,585	87,519	-

Item 6. **Exhibits**

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on this 26th day of July, 2007.

WHITING PETROLEUM CORPORATION

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

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

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

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(31.1)	Certification by Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.