WHITING PETROLEUM CORP
Form 10-Q
October 31, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended September 30, 2006

or

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

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 þ Accelerated filer o Non-accelerated filer o

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

Number of shares of the registrant s common stock outstanding at October 16, 2006: 36,948,618 shares.

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PART I FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

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

	September 30, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,750	$ 10,382
Accounts receivable trade, net	91,424	101,066
Deferred income taxes	2,646	15,121
Prepaid expenses and other	8,691	5,595
Total current assets	106,511	132,164
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	2,722,492	2,353,372
Unproved properties	56,811	21,671
Other property and equipment	42,323	26,235
Total property and equipment	2,821,626	2,401,278
Less accumulated depreciation, depletion and amortization	(452,874)	(338,420)
Total property and equipment, net	2,368,752	2,062,858
DEBT ISSUANCE COSTS	20,328	23,660
OTHER LONG-TERM ASSETS	17,066	16,514
TOTAL	$ 2,512,657	$ 2,235,196

See notes to condensed consolidated financial statements.

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

	September 30, 2006	December 31, 2005
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 71,113	$ 68,033
Accrued interest	20,509	11,894
Oil and gas sales payable	23,464	21,154
Accrued employee compensation and benefits	16,191	15,351
Production taxes payable	19,184	13,259
Current portion of tax sharing liability	4,057	4,254
Current portion of derivative liability	2,782	34,569
Total current liabilities	157,300	168,514
NON-CURRENT LIABILITIES:		
Long-term debt	945,169	875,098
Asset retirement obligations	34,827	32,246
Production Participation Plan liability	25,229	19,287
Tax sharing liability	26,322	24,576
Deferred income taxes	153,908	91,577
Long-term derivative liability	9,801	21,817
Other long-term liabilities	4,489	4,219
Total non-current liabilities	1,199,745	1,068,820
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 36,948,618 and 36,841,823 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively	37	37
Additional paid-in capital	753,729	753,093
Accumulated other comprehensive loss	(7,951)	(34,620)
Deferred compensation		(2,031)
Retained earnings	409,797	281,383
Total stockholders equity	1,155,612	997,862
TOTAL	$ 2,512,657	$ 2,235,196

See notes to condensed consolidated financial statements.

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

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 207,752	$ 153,386	$ 601,259	$ 374,829
Loss on oil and natural gas hedging activities	(375)	(13,744)	(9,859)	(20,689)
Interest income and other	210	153	836	319
Total revenues and other income	207,587	139,795	592,236	354,459
COSTS AND EXPENSES:				
Lease operating	46,183	27,792	135,236	70,732
Production taxes	12,492	10,103	36,819	24,558
Depreciation, depletion and amortization	42,737	23,318	116,947	64,400
Exploration and impairment	6,647	4,384	22,903	11,740
General and administrative	10,035	6,744	29,285	20,017
Change in Production Participation Plan liability	1,799	1,609	5,942	1,878
Interest expense	18,879	11,640	54,479	25,018
Total costs and expenses	138,772	85,590	401,611	218,343
INCOME BEFORE INCOME TAXES	68,815	54,205	190,625	136,116
INCOME TAX EXPENSE:				
Current	(4,075)	4,440	537	9,177
Deferred	23,346	16,483	61,674	43,364
Total income tax expense	19,271	20,923	62,211	52,541
NET INCOME	$ 49,544	$ 33,282	$ 128,414	$ 83,575
NET INCOME PER COMMON SHARE, BASIC	$ 1.35	$ 1.12	$ 3.50	$ 2.82
NET INCOME PER COMMON SHARE, DILUTED	$ 1.35	$ 1.12	$ 3.49	$ 2.81
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	36,751	29,707	36,742	29,688

WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	36,838	29,725	36,810	29,705

See notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 128,414	$ 83,575
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	116,947	64,400
Deferred income taxes	61,674	43,364
Amortization of debt issuance costs and debt discount	3,922	2,754
Accretion of tax sharing liability	1,549	1,860
Stock-based compensation	2,915	2,222
Unproved leasehold impairments	1,742	1,928
Change in Production Participation Plan liability	5,942	1,878
Other non-current	(1,887)	(2,339)
Changes in current assets and liabilities:		
Accounts receivable trade	9,642	(17,791)
Prepaid expenses and other	(7,132)	867
Accounts payable	10,902	8,339
Accrued interest	8,615	9,328
Other liabilities	8,635	10,797
Net cash provided by operating activities	351,880	211,182
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(79,169)	(427,331)
Drilling capital expenditures	(349,523)	(103,896)
Deposit on North Ward Estes acquisition		(45,900)
Acquisition of Partnership interests, net of cash acquired of $26		(30,433)
Net cash used in investing activities	(428,692)	(607,560)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of 7.25% Senior Subordinated debt due 2013		216,715
Issuance of long-term debt under credit agreement	255,000	395,000
Payments on long-term debt under credit agreement	(185,000)	(200,000)
Debt issuance costs	(103)	(9,684)
Tax effect from restricted stock vesting	283	229
Net cash provided by financing activities	70,180	402,260
NET CHANGE IN CASH AND CASH EQUIVALENTS	(6,632)	5,882
CASH AND CASH EQUIVALENTS:		
Beginning of period	10,382	1,660

End of period	$	3,750	$	7,542
SUPPLEMENTAL CASH FLOW DISCLOSURES:				
Cash paid for income taxes	$	3,662	$	10,676
Cash paid for interest	$	40,697	$	10,465
NONCASH INVESTING ACTIVITIES:				
Decrease in accrued capital expenditures	$	7,824	$	10,733

See notes to condensed consolidated financial statements.

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

	Common Stock		Additional	Accumulated Other			Total	
	Shares	Amount	Paid-in Capital	Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Stockholders Equity	Comprehensive Income
BALANCES January 1, 2005	29,718	$ 30	$ 455,635	$ (1,025)	$ (1,715)	$ 159,461	$ 612,386	
Net income						121,922	121,922	$ 121,922
Change in derivative fair values, net of related taxes				(54,089)			(54,089)	(54,089)
Realized loss on settled derivative contracts, net of related taxes				20,494			20,494	20,494
Restricted stock issued	85		3,407		(3,407)			
Restricted stock forfeited	(9)		(230)		230			
Restricted stock used for tax withholdings	(6)		(241)				(241)	
Tax effect from restricted stock vesting			237				237	
Issuance of stock secondary offering	6,612	7	277,110				277,117	
Issuance of stock North Ward Estes acquisition	442		17,175				17,175	
Amortization of deferred compensation					2,861		2,861	
BALANCES December 31, 2005	36,842	37	753,093	(34,620)	(2,031)	281,383	997,862	$ 88,327

See notes to condensed consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)
(In thousands, except per share data)

1. BASIS OF PRESENTATION

Description of Operations Whiting Petroleum Corporation (Whiting or the Company) is an independent oil and gas company that acquires, 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.

Consolidated Financial Statements The unaudited consolidated financial statements include the accounts of Whiting 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 significant 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 2005 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 2005 Annual Report on Form 10-K.

Earnings Per Share Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of basic and diluted 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 outstanding and other dilutive securities. 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 December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment* (SFAS 123R). This Statement is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and its related implementation guidance. SFAS 123R requires a company to measure the grant date fair value of equity awards given to employees in exchange for services and recognize that cost, less estimated forfeitures, over the period that such services are performed. The Company adopted SFAS 123R on January 1, 2006 using the modified prospective transition method.

Prior to adopting SFAS 123R, the Company accounted for stock-based compensation under SFAS 123, whereby the Company s policy was to recognize actual forfeitures of restricted stock only when they occurred rather than estimate them at the grant date and subsequently true-up estimated forfeitures to actuals. SFAS 123R requires companies to include

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forfeitures as part of the grant date estimate of compensation cost. Under the modified prospective method of adopting SFAS 123R, compensation cost recognized for the nine months ended September 30, 2006 includes (a) compensation cost for all restricted stock awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value, less estimated forfeitures, and (b) compensation cost for all share-based payments granted and vested subsequent to January 1, 2006, based on the grant date fair value, less estimated forfeitures. A cumulative effect of change in accounting principle to recognize the impact of including forfeitures, as part of the grant date estimate of compensation cost for all restricted stock awards granted prior to January 1, 2006, resulted in an insignificant credit to income for the nine months ended September 30, 2006. In accordance with the modified prospective method, prior period results have not been restated.

For the three and nine months ended September 30, 2006, the Company recognized share-based compensation costs of $0.9 million and $2.5 million, respectively, in general and administrative expenses and $0.2 million and $0.4 million, respectively, in exploration expenses in the Company s consolidated statement of income. The Company did not capitalize any share-based compensation costs for the nine months ended September 30, 2006. The adoption of SFAS 123R had a minimal impact on the Company s income before income taxes and net income, and had no effect on basic or diluted earnings per share, for the three and nine months ended September 30, 2006, as presented in the Company s consolidated statements of income.

Under the provisions of SFAS 123R, the recognition of deferred compensation at the date restricted stock is granted is no longer required. Therefore, in the first quarter of 2006, the amount that had been previously recorded as Deferred compensation in the Company s consolidated balance sheets was reversed in its entirety to additional paid-in capital.

In addition, the adoption of SFAS 123R required that the Company classify certain tax benefits obtained upon restricted stock vesting, which result from tax deductions in excess of compensation cost recognized for book purposes, as financing cash flows rather than operating cash flows. The Company recognized an insignificant income tax benefit for share-based compensation for the three months ended September 30, 2006, and $0.3 million in income tax benefits relating to share-based compensation for the nine months ended September 30, 2006.

2. ACQUISITIONS

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. As part of this transaction, the operator will pay 100% of the Company s drilling and completion costs for the first three wells in the project.

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

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MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. The average daily production from the properties was approximately 638 MBOE/d as of the acquisition effective date.

The Company funded its 2006 acquisitions with cash on hand as well as through borrowings under Whiting Oil and Gas Corporation s credit agreement.

2005 Acquisitions

North Ward Estes and Ancillary Properties On October 4, 2005, the Company acquired the operated interest in the North Ward Estes field in Ward and Winkler counties, Texas, and certain smaller fields located in the Permian Basin. The purchase price was $459.2 million, consisting of $442.0 million in cash and 441,500 shares of the Company s common stock, for estimated proved reserves of approximately 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of approximately $5.58 per BOE of estimated proved reserves. The average daily production from the properties was approximately 4.6 MBOE/d as of the acquisition effective date. The Company funded the cash portion of the purchase price with the net proceeds from the Company s public offering of common stock and private placement of 7% Senior Subordinated Notes due 2014, both of which closed on October 4, 2005.

Postle Field On August 4, 2005, the Company acquired the operated interest in producing oil and natural gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of approximately 40.3 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of approximately $8.52 per BOE of estimated proved reserves. The average daily production from the properties was approximately 4.2 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under Whiting Oil and Gas Corporation s credit agreement.

Limited Partnership Interests On June 23, 2005, the Company acquired all of the limited partnership interests in three institutional partnerships managed by its wholly-owned subsidiary, Whiting Programs, Inc. The partnership properties are located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The purchase price was $30.5 million for estimated proved reserves of approximately 2.9 MMBOE as of the acquisition effective date of January 1, 2005, resulting in a cost of approximately $10.52 per BOE of estimated proved reserves. The average daily production from the properties was 0.7 MBOE/d as of the acquisition effective date. The Company funded the acquisition with cash on hand.

Green River Basin On March 31, 2005, the Company acquired operated interests in five producing natural gas fields in the Green River Basin of Wyoming. The purchase price was $65.0 million for estimated proved reserves of approximately 8.4 MMBOE as of the acquisition effective date of March 1, 2005, resulting in a cost of $7.74 per BOE of estimated proved reserves. The average daily production from the properties was approximately 1.1 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under Whiting Oil and Gas Corporation s credit agreement and with cash on hand.

As these acquisitions were recorded using the purchase method of accounting, the results of operations from the acquisitions are included with the Company s results from the

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respective acquisition dates noted above. The table below summarizes the allocation of the purchase price for each purchase transaction based on the acquisition date fair values of the assets acquired and the liabilities assumed (in thousands).

	Postle Field	N. Ward Estes and Ancillary	All Other 2005 Acquisitions
Purchase Price:			
Cash paid, net of cash acquired	$ 343,000	$ 442,000	$ 95,433
Common stock issued		17,175	
Total	$ 343,000	$ 459,175	$ 95,433
Allocation of Purchase Price:			
Working capital	$	$	$ 2,096
Oil and gas properties	343,513	463,340	95,832
Other long-term assets	243		
Other non-current liabilities	(756)	(4,165)	(2,495)
Total	$ 343,000	$ 459,175	$ 95,433

3. 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.

All derivatives are recognized on the balance sheet and measured at fair value. Unrealized gains and losses on effective cash flow hedge derivatives are recorded as a component of accumulated other comprehensive income (loss). When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transferred from accumulated other comprehensive income (loss) to earnings. Realized gains and losses on commodity hedge derivatives are recognized as gain (loss) on oil and natural gas hedging activities , and the ineffective portion of hedge derivatives, if any, is recorded as a derivative fair value gain or loss in the consolidated statements of income. Realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Derivative settlements are included in cash flows from operating activities.

At September 30, 2006, accumulated other comprehensive loss consisted of $12.6 million ($8.0 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 months ended September 30, 2006 and 2005, Whiting recognized

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realized losses of $0.4 million and $13.7 million, respectively, on commodity derivative settlements. For the nine months ended September 30, 2006 and 2005, Whiting recognized realized losses of $9.9 million and $20.7 million, respectively, on commodity derivative settlements.

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

4. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2006 and December 31, 2005 (in thousands):

	September 30, 2006	December 31, 2005
Credit Agreement	$ 330,000	$ 260,000
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $726 and $848, respectively	147,712	148,014
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,543 and $2,916, respectively	217,457	217,084
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$ 945,169	$ 875,098

Credit Agreement The Company s wholly-owned subsidiary, Whiting Oil and Gas Corporation, has a $1.2 billion credit agreement with a syndicate of banks that, as of September 30, 2006, had a borrowing base of $800.0 million. The borrowing base under the credit agreement is determined at the discretion of the lenders based on the collateral value of proved reserves that have been mortgaged to the lenders and is subject to regular redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. As of September 30, 2006, the outstanding principal balance under the credit agreement was $330.0 million. In October 2006, the syndicate of banks approved an increase in the borrowing base under the credit agreement to $875.0 million, effective November 1, 2006.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas Corporation may, throughout the term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect from time to time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas Corporation or other designated subsidiaries of the Company from time to time in an aggregate amount not to exceed $50.0 million. As of September 30, 2006, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues, at Whiting Oil and Gas Corporation s option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% 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 Corporation 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 September 30, 2006, the interest rate on the outstanding principal balance under the credit agreement was 6.4%.

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 (as defined in the credit agreement) ratio 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 Corporation and its wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes, or other payments to the Company. 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 September 30, 2006. The credit agreement is secured by a first lien on all of Whiting Oil and Gas Corporation s 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 Corporation under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged all of its properties included in the borrowing base for the credit agreement as security for its guarantee.

Senior Subordinated Notes In October 2005, the Company issued $250.0 million of 7% Senior Subordinated Notes due 2014 at par. The estimated fair value of these notes was $240.0 million as of September 30, 2006.

In April 2005, the Company 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 of $3.3 million is being amortized to interest expense over the term of the notes yielding an effective interest rate of 7.5%. The estimated fair value of these notes was $215.6 million as of September 30, 2006.

In May 2004, the Company 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 of $1.1 million is being amortized to interest expense over the term of the notes yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $147.6 million as of September 30, 2006.

The notes are unsecured obligations of the Company and are subordinated to all of the Company s senior debt. The indentures governing all of the above notes contain various restrictive covenants that are substantially identical and may limit the Company s and its subsidiaries 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. In addition, Whiting Oil and Gas Corporation s credit agreement restricts the ability of the Company s subsidiaries to make certain payments, including principal on the notes, to the Company. The Company was in compliance with these covenants as of September 30, 2006. Three of the Company s subsidiaries, Whiting Oil and Gas Corporation, 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 the Company has no independent assets or operations.

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 under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, 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 September 30, 2006, the Company has recorded a long-term liability of $1.6 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.

5. ASSET RETIREMENT OBLIGATIONS

The Company s asset retirement obligations primarily represent the estimated present value of amounts expected to be incurred to plug, abandon and remediate producing properties (including removal of certain onshore and offshore facilities in California) at the end of their productive lives, 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 is a summary of the asset retirement obligation activity for the nine months ended September 30, 2006 (in thousands):

Asset retirement obligation, January 1, 2006	$ 32,246
Additional liabilities incurred	1,724
Revisions in estimated cash flows	957
Accretion expense	1,693
Obligations on sold properties	(661)
Liabilities settled	(1,132)
Asset retirement obligation, September 30, 2006	$ 34,827

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. In periods prior to January 1, 2006, the Company had granted 197,573 shares of restricted stock under this plan, of which 16,989 shares were forfeited and 6,122 shares were cancelled when used for employee tax withholdings. All restricted stock awards granted to date vest ratably over three years.

The following table shows a summary of the Company s nonvested restricted stock as of September 30, 2006 as well as activity during the nine 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, 2006	145,763	$ 32.34
Granted	125,999	$ 43.38
Vested	(58,409)	$ 27.81
Forfeited	(9,152)	$ 37.65
Restricted stock awards nonvested, September 30, 2006	204,201	$ 39.35

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. SFAS 123R requires that expected forfeitures be included as part of the grant date estimate of compensation cost. Prior to adopting SFAS 123R, the Company reduced share-based compensation expense for forfeitures only when they occurred.

As of September 30, 2006, there was $4.0 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.

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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. The dividend was paid on March 9, 2006 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 par value (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. EQUITY 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 natural 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. Current accrued compensation expense under the Plan for the nine months ended September 30, 2006 and 2005 amounted to $10.2 million and $6.6 million, respectively, charged to general and administrative expense and $1.8 million and $1.2 million, respectively, charged to exploration expense.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At September 30, 2006, the Company used five-year average historical NYMEX prices of $44.80 for crude oil and $5.51 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 established 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 September 30, 2006, 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 $77.3 million. This amount includes $7.8 million attributable to proved undeveloped oil and gas properties and $12.0 million relating to the short-term portion of the Production Participation Plan liability, which has been accrued currently for 2006 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. The Company has no intention to terminate the Plan.

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The following table presents changes in the estimated long-term liability related to the Plan for the nine months ended September 30, 2006 (in thousands):

Production Participation Plan liability, January 1, 2006	$ 19,287
Change in liability for accretion, vesting and change in estimate	17,959
Reduction in liability for cash payments accrued and recognized as compensation expense	(12,017)
Production Participation Plan liability, September 30, 2006	$ 25,229

The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the 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 oil and gas properties rather than current period performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items (in thousands):

	Nine Months Ended September 30,	
	2006	**2005**
General and administrative expense	$ 5,069	$ 1,578
Exploration expense	873	300
Total	$ 5,942	$ 1,878

8. 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 23,000 square feet of office space in Midland, Texas through February 28, 2008. Rental expense for the first nine months of 2006 and 2005 was $1.5 million and $1.1 million, respectively. A summary of future minimum lease payments under its non-cancelable operating leases as of September 30, 2006 is as follows (in thousands):

2006	$ 425
2007	1,682
2008	1,481
2009	1,469
2010	1,224
Total	$ 6,281

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 eight years, whereby the Company has committed to buy certain volumes of CO_2 for a fixed fee, subject to annual escalation, for use in enhanced recovery projects in the Postle field in Texas County, Oklahoma and the North Ward Estes field in Ward County, Texas. The purchase agreements are with different suppliers. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO_2 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 September 30, 2006, future commitments under the purchase agreements amounted to $313.0 million through 2014.

Drilling Contracts The Company entered into three separate three-year agreements in 2005 for rigs drilling in the Rocky Mountains region and one agreement in February 2006 for a rig drilling in North Dakota. As of September 30, 2006, these agreements had total commitments of $22.7 million and early termination would require maximum penalties of $16.6 million. No other drilling rigs working for the Company are currently under long-term contracts or contracts which cannot be terminated at the end of the well that is currently being drilled.

Price-sharing Agreement The Company, as part of a 2002 purchase transaction, agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result of the escalation clause, the sharing amount at January 1, 2006 increased to 50% of the actual price received in excess of $20.56 per barrel. Approximately 42,100 net barrels of crude oil per month (5% of September 2006 net crude oil production) are currently subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. The Company paid $7.0 million and $5.1 million for the nine-month periods ended September 30, 2006 and 2005, respectively, under this agreement.

Tax Separation and Indemnification Agreement with Alliant Energy Prior to Whiting s initial public offering in November 2003, the Company was a wholly-owned indirect subsidiary of Alliant Energy Corporation (Alliant Energy), a holding company whose primary businesses are utility companies. In connection with Whiting s initial public offering, 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 the assets of Whiting and its subsidiaries 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 the Company s 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 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 bases not occurred. In 2014, Whiting will be obligated to pay Alliant Energy 90% of the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. Future tax benefits in total will approximate $61.1 million. The Company has estimated that total payments to Alliant Energy will approximate $47.8 million on an undiscounted basis, with a present value of $30.4 million.

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During the first nine months of 2006, the Company did not make any payments under this agreement but did recognize $1.5 million of accretion expense which is included as a component of interest expense. The Company s estimated payment of $4.1 million to be made in 2006 under this agreement is reflected as a current liability at September 30, 2006.

The Tax Separation Agreement provides that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of Whiting s future obligation to Alliant Energy. For purposes of this calculation, management has assumed that such tax rates remain constant throughout the remaining 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 are made to the anticipated cash flows 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 cash flows. However, if there are substantial changes to the estimated cash flows owed under this agreement, then a gain or loss is recognized in the consolidated statement of income during the period in which the modification has been made.

Litigation The Company is subject to litigation claims and governmental and regulatory controls 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 financial position, cash flows or results of operations.

9. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The adoption of FIN 48 is not expected to have a material impact on the Company s consolidated financial position or results of operations. The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. 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 the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The interpretation is effective for fiscal years beginning after December 15, 2006.

In September 2006, the FASB issued Statement No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132R* (SFAS 158). The adoption of SFAS 158 is not expected to have a material impact on the Company s consolidated financial position or results of operations, as the Company does not currently have any defined benefit pension or other postretirement plans. SFAS 158 requires companies to recognize in their balance sheets an asset for a plan s overfunded status or a liability for a plan s underfunded status, measure a plan s assets and its obligations that determine its funded status as of the date of their fiscal year-end, and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. Those changes will be reported in comprehensive income and as a separate component of stockholders equity. Additional

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footnote disclosures will also be required. SFAS 158 is effective for fiscal years ending after December 15, 2006.
In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). The adoption of SAB 108 is not expected to have a material impact on the Company s consolidated financial position or results of operations. SAB 108 provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 is effective for fiscal years ending on or after November 15, 2006, allowing a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006, for errors that were not previously deemed material, but are material under the guidance in SAB 108.

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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 Whiting 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.

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 should or 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. Some, but not all, of the risks and uncertainties include: declines in oil or gas prices; our level of success in exploitation, exploration, development and production activities; the timing of our exploration and development expenditures, including our ability to obtain drilling rigs; 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; 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 facility; 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; risks arising out of our hedging transactions and other risks described under the caption Risk Factors in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Overview

We are engaged in crude oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. Over the last five years, we have emphasized the acquisition of properties that provided current production and upside potential through further development. Our drilling activity is directed at this development, specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and development allows us to direct our capital resources to what we believe to be the most advantageous investments.

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We have historically acquired operated as well as 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 provided a foothold 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 are of the opinion 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.

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, our results of operations, the quantities of oil and gas reserves that we can economically produce and our access to capital.

On August 29, 2006, we acquired a 15% working interest in approximately 170,000 leased acres in the central Utah Hingeline play. As part of this transaction, the operator will pay 100% of our drilling and completion costs for the first three wells in the project. Drilling operations on the first of the three planned wells are expected to begin in the fourth quarter of 2006.

On August 15, 2006, we acquired 65 producing properties, a gathering line, gas processing plant and 30,437 net acres of leasehold held by production in Michigan (Michigan Properties), acquiring total estimated proved reserves of 1.4 MMBOE as of the acquisition effective date for a purchase price of $26.0 million. We operate 85% of the acquired properties.

On June 1, 2006, we acquired the Postle field oil gathering system and oil transportation line extending 13 miles from the eastern side of the Postle field to a connection point with an interstate oil pipeline in Hooker, Oklahoma. We purchased the oil gathering system and pipeline for $5.3 million in cash.

We completed four separate acquisitions of producing properties during 2005. The combined purchase price for these four acquisitions was $897.7 million for total estimated proved reserves as of the effective dates of the acquisitions of approximately 133.7 MMBOE.

Although independent engineers estimated probable and possible reserves relating to certain 2006 and 2005 acquisitions, we, consistent with our present acquisition practices, have associated all acquisition costs with proved reserves. Because of our substantial recent acquisition activity, our discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to our future results of operations. Our historical results include the results from our recent acquisitions beginning on the following dates: Utah Hingeline, August 29, 2006; Michigan Properties, August 15, 2006; North Ward Estes and Ancillary Properties, October 4, 2005; Postle Properties, August 4, 2005; Limited Partnership Interests, June 23, 2005; and Green River Basin, March 31, 2005.

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Results of Operations

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Selected Operating Data:

	Nine Months Ended September 30,	
	2006	2005
Net production:		
Oil (MMbls)	7.3	4.7
Natural gas (Bcf)	24.1	22.4
Total production (MMBOE)	11.4	8.4
Oil and natural gas sales (in millions):		
Oil(1)	$ 436.5	$ 235.0
Natural gas(1)	164.8	139.8
Total oil and natural gas sales	$ 601.3	$ 374.8
Average sales prices:		
Oil (per Bbl)	$ 59.52	$ 50.37
Effect of oil hedges on average price (per Bbl)	(1.28)	(4.05)
Oil net of hedging (per Bbl)	$ 58.24	$ 46.32
Average NYMEX price	$ 68.29	$ 55.45
Natural gas (per Mcf)	$ 6.83	$ 6.25
Effect of natural gas hedges on average price (per Mcf)	(0.02)	(0.08)
Natural gas net of hedging (per Mcf)	$ 6.81	$ 6.17
Average NYMEX price	$ 7.46	$ 7.18
Cost and expense (per BOE):		
Lease operating expenses	$ 11.91	$ 8.42
Production taxes	$ 3.24	$ 2.93
Depreciation, depletion and amortization expense	$ 10.30	$ 7.67
General and administrative expenses	$ 2.58	$ 2.38

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $226.4 million to $601.3 million in the first nine months of 2006 compared to the first nine months of 2005. Sales are a function of sales volumes and average sales prices. Our oil sales volumes increased 57% and our natural gas sales volumes increased 8% between periods. The volume increases resulted from acquisitions completed in 2005 and 2006 and successful drilling activities over the past year that produced new sales volumes that more than offset natural production decline. Our average price for oil increased 18% and our average price for natural gas sales increased 9% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 54% of our oil volumes during the first nine months of 2006 incurring a hedging loss of $9.4 million, and 61% of our oil volumes during the first nine months of 2005 incurring a loss of $18.9 million. We hedged 58% of our natural gas volumes during the first nine months of 2006, incurring a hedging loss of $0.5 million, and 60% of our natural gas volumes during the first nine months of 2005, incurring a

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hedging loss of $1.8 million. See Item 3, Qualitative and Quantitative Disclosures About Market Risk for a list of our outstanding oil and natural gas hedges as of October 16, 2006.

Lease Operating Expenses. Our lease operating expenses increased $64.5 million to $135.2 million in the first nine months of 2006 compared to the first nine months of 2005. The increase resulted primarily from costs associated with new property acquisitions during 2005 and 2006 and successful drilling activities over the past year. Our lease operating expense as a percentage of oil and gas sales increased from 19% during the first nine months of 2005 to 23% during the first nine months of 2006. Our lease operating expenses per BOE increased from $8.42 during the first nine months of 2005 to $11.91 during the first nine months of 2006. The increase of 41% on a BOE basis was primarily caused by higher energy costs and increases in the cost of oil field goods and services due to higher demand in the industry. Approximately 40% of our lease operating expenses directly or indirectly relate to energy prices. We also incurred a high level of workover activity on recently acquired properties during the first nine months of 2006, which amounted to $5.9 million, as compared to $2.5 million of workover activity during the first nine months of 2005.

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 nine months of 2006 and 2005 were 6.1% and 6.6%, respectively, of oil and gas sales. The 2006 rate was lower than the 2005 rate due to the change in the property mix associated with recent acquisitions.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $52.5 million to $116.9 million during the first nine months of 2006 as compared to the first nine months of 2005. The increase resulted from higher production volumes in 2006 and an increase in our DD&A rate. On a BOE basis, the rate increased from $7.67 during the first nine months of 2005 to $10.30 in the first nine months of 2006. The primary factors causing the DD&A rate increase were higher costs of adding proved developed reserves during the fourth quarter of 2005 and first nine months of 2006, downward net reserve revisions, and an increase in drilling expenditures, as costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. Also contributing to our higher DD&A rate was the association of all 2005 property acquisition costs with proved reserves, thereby including all such costs in our DD&A rate immediately when incurred. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2006	**2005**
Depletion and amortization	$ 113,389	$ 61,745
Depreciation	1,865	920
Accretion of asset retirement obligations	1,693	1,735
Total	$ 116,947	$ 64,400

Exploration and Impairment Costs. Our exploration and impairment costs increased $11.2 million to $22.9 million in the first nine months of 2006 compared to the first nine months of 2005. The components of exploration and impairment costs are as follows (in thousands):

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	Nine Months Ended September 30,	
	2006	2005
Exploration	$ 21,161	$ 9,812
Impairment	1,742	1,928
Total	$ 22,903	$ 11,740

Higher exploration costs resulted from two exploratory dry holes drilled in the Rocky Mountains region and one exploratory dry hole drilled in the Gulf Coast region, totaling $5.3 million for the first nine months of 2006. In the first nine months of 2005, we drilled a total of five exploratory dry holes, totaling $3.1 million. We incurred $7.8 million in geological and geophysical expenses during the first nine months of 2006, up $4.9 million from the same period in 2005. We also hired additional exploration personnel to support the increased drilling budget from $223.6 million incurred in 2005 to a range of $420.0 million to $440.0 million in 2006. The impairment charge in 2006 related to amortized leasehold costs associated with individually insignificant unproved properties. The impairment charge in 2005 related to unrecoverable costs associated with our investment in the Cherokee Basin of Kansas.

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

	Nine Months Ended September 30,	
	2006	2005
General and administrative expenses	$ 44,749	$ 27,770
Reimbursements and allocations	(15,464)	(7,753)
General and administrative expenses, net	$ 29,285	$ 20,017

General and administrative expenses before reimbursements and allocations increased $17.0 million to $44.7 million during the first nine months of 2006. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $11.9 million and an increase in the current year accrual for cash payments under our Production Participation Plan of $4.3 million. Personnel salary expenses were higher in 2006 due to an increase in our employee base resulting from our continued growth. The increased cost of the Production Participation Plan was caused primarily by higher 2006 production volumes and higher average sales prices between periods. The increase in reimbursements and allocations was caused by a higher number of operated properties due to recent acquisitions and drilling activities during the fourth quarter of 2005 and first nine months of 2006. As a percentage of oil and gas sales, our net general and administrative expenses remained consistent at 5%.

Change in Production Participation Plan Liability. For the nine months ended September 30, 2006, this non-cash expense increased $4.1 million from the same period in 2005. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2007 under our Production Participation Plan. Although payments take place over the life of oil and gas properties contributed to the Plan, some properties for over 20 years, we must expense the present value of estimated future payments over the Plan s five year vesting period. The increase in expense primarily reflects changes to future cash flow estimates due to the effect of a sustained higher price environment and recent acquisitions, as well as employees continued vesting in the Plan. Assumptions that are used to calculate this liability are subject to estimation and will vary from period to period based on the current market for oil and gas prices, discount rates and overall market conditions.

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

	Nine Months Ended September 30,	
	2006	**2005**
Credit Agreement	$ 15,219	$ 5,918
Senior Subordinated Notes	33,350	14,373
Amortization of debt issue costs and debt discount	3,922	2,754
Accretion of tax sharing liability	1,549	1,860
Other	742	113
Capitalized interest	(303)	
Total interest expense	$ 54,479	$ 25,018

The increase in interest expense was mainly due to the April 2005 issuance of $220.0 million of 7.25% Senior Subordinated Notes due 2013, the October 2005 issuance of $250.0 million of 7% Senior Subordinated Notes due 2014 and additional borrowings outstanding under our credit agreement. The higher amortization of debt issue costs and debt discount from the end of third quarter of 2005 to the end of the third quarter of 2006 related to additional debt issue costs associated with the April 2005 and October 2005 issuances of Senior Subordinated Notes, and the amendment to the credit agreement.

Our weighted average debt outstanding in the first nine months of 2006 was $934.2 million versus $441.6 million in the first nine months of 2005. Our weighted average effective cash interest rate was 7.0% in the first nine months of 2006 versus 6.2% in the first nine months of 2005. 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 7.5% in the first nine months of 2006 versus 7.0% in the first nine months of 2005.

Income Tax Expense. Income tax expense totaled $62.2 million for the first nine months of 2006 and $52.5 million for the first nine months of 2005. Our effective income tax rate decreased from 38.6% for the first nine months of 2005 to 32.6% for the first nine months of 2006 primarily due to the recognition of a $4.3 million deferred tax benefit for 2005 enhanced oil recovery (EOR) tax credits, a $2.3 million benefit relating to a true-up of our effective rate to our 2005 state returns as filed and deferred tax benefits of $1.2 million as a result of recently enacted tax legislation in Texas and Michigan.

EOR credits are a credit against federal income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed enhanced tertiary recovery methods. Federal EOR credits are subject to phase-out according to the level of average domestic crude prices. Due to recent high oil prices, we will not be earning any federal EOR credits during 2006.

The current portion of income tax expense was $0.5 million for the nine months ended September 30, 2006 compared to $9.2 million in the same period in 2005, mainly due to one-time benefits for a true-up of our effective tax rate to our 2005 state returns. In the third quarter of 2006, we reported a tax loss on our 2005 federal return as filed, primarily due to intangible drilling deductions allowed, which resulted in a federal tax refund of $4.7 million.

Net Income. Net income increased from $83.6 million during the first nine months of 2005 to $128.4 million during the first nine months of 2006. The primary reasons for this increase included a 35% increase in equivalent volumes sold and 24% higher oil and gas prices net of hedging between periods as well as certain income tax benefits recognized during the first nine months of 2006, which were partially offset by higher lease operating expense, production taxes, DD&A, exploration and impairment, general and administrative, Production Participation Plan, interest expenses, and income taxes resulting from our continued growth.

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005

Selected Operating Data:

	Three Months Ended September 30, 2006	2005
Net production:		
Oil (MMbls)	2.5	1.7
Natural gas (Bcf)	8.2	7.4
Total production (MMBOE)	3.9	2.9
Oil and natural gas sales (in millions):		
Oil(1)	$ 156.7	$ 99.1
Natural gas(1)	51.1	54.3
Total oil and natural gas sales	$ 207.8	$ 153.4
Average sales prices:		
Oil (per Bbl)	$ 62.11	$ 57.84
Effect of oil hedges on average price (per Bbl)	(0.15)	(6.98)
Oil net of hedging (per Bbl)	$ 61.96	$ 50.86
Average NYMEX price	$ 70.55	$ 63.16
Natural gas (per Mcf)	$ 6.23	$ 7.34
Effect of natural gas hedges on average price (per Mcf)		(0.24)
Natural gas net of hedging (per Mcf)	$ 6.23	$ 7.10
Average NYMEX price	$ 6.58	$ 8.51
Cost and expense (per BOE):		
Lease operating expenses	$ 11.88	$ 9.43
Production taxes	$ 3.21	$ 3.43
Depreciation, depletion and amortization expense	$ 10.99	$ 7.91
General and administrative expenses	$ 2.58	$ 2.29

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $54.4 million to $207.8 million in the third quarter of 2006 compared to the third quarter of 2005. Sales are a function of sales volumes and average sales prices. Our oil sales volumes increased 47% and our natural gas sales volumes increased 11% between periods. The volume increases resulted from acquisitions completed in 2005 and 2006 and successful drilling activities over the past year that produced new sales volumes that more than offset natural production decline. Our average price for oil increased 7% and our average price for natural gas sales decreased 15% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 54% of our oil volumes during the third quarter of 2006 incurring a hedging loss of $0.4 million, and 62% of our oil volumes during the third quarter of 2005 incurring a hedging loss of $11.9 million. We hedged 59% of our natural gas volumes during the third quarter of 2006, incurring no hedging loss or gain, and 61% of our natural gas volumes during the third quarter of 2005, incurring a hedging loss of $1.8 million. See Item 3, Qualitative and Quantitative Disclosures About Market Risk for a list of our outstanding oil and natural gas hedges as of October 16, 2006.

Lease Operating Expenses. Our lease operating expenses increased $18.4 million to $46.2 million in the third quarter of 2006 compared to the third quarter of 2005. The increase resulted primarily from costs associated with new property acquisitions during 2005 and 2006 and successful drilling activities over the past year. Our lease operating expense as a percentage of oil and natural gas sales increased from 18% during the third quarter of 2005 to 22% during the third quarter of 2006. Our lease operating expenses per BOE increased from $9.43 during the third quarter of 2005 to $11.88 during the third quarter of 2006. The increase of 26% on a BOE basis was primarily caused by higher energy costs and increases in the cost of oil field goods and services due to higher demand in the industry. Approximately 40% of our lease operating expenses directly or indirectly relate to energy prices. We also incurred a high level of workover activity on recently acquired properties during the third quarter of 2006 which amounted to $1.8 million, as compared to $0.9 million of workover activity during the third quarter of 2005.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in the various taxing jurisdictions. Our production taxes for the third quarter of 2006 and 2005 were 6.0% and 6.6%, respectively, of oil and natural gas sales. The 2006 rate was lower than the 2005 rate due to the change in the property mix associated with recent acquisitions.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $19.4 million to $42.7 million during the third quarter of 2006 as compared to the third quarter of 2005. The increase resulted from higher production volumes in 2006 and an increase in our DD&A rate. On a BOE basis, the rate increased from $7.91 during the third quarter of 2005 to $10.99 in the third quarter of 2006. The primary factors causing the DD&A rate increase were higher costs of adding proved developed reserves during the fourth quarter of 2005 and first three quarters of 2006, downward net reserve revisions, and an increase in drilling expenditures, as costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. Also contributing to our higher DD&A rate was the association of all 2005 property acquisition costs with proved reserves, thereby including all such costs in our DD&A rate immediately when incurred. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2006	**2005**
Depletion and amortization	$ 41,430	$ 22,337
Depreciation	735	360
Accretion of asset retirement obligations	572	621
Total	$ 42,737	$ 23,318

Exploration and Impairment Costs. Our exploration and impairment costs increased $2.3 million to $6.6 million in the third quarter of 2006 compared to the third quarter of 2005. The components of exploration and impairment costs are as follows (in thousands):

	Three Months Ended September 30,	
	2006	**2005**
Exploration	$ 5,618	$ 4,384
Leasehold Impairments	1,029	
Total	$ 6,647	$ 4,384

We did not drill any exploratory dry holes during the third quarter of 2006. In the third quarter of 2005, we drilled a total of two exploratory dry holes, totaling $1.3 million. We incurred $3.0 million in geological and geophysical expenses during the third quarter of 2006, up $1.3 million from the same period in 2005. We also hired additional exploration personnel to support the increased drilling budget from $223.6 million incurred in 2005 to a range of $420.0 million to $440.0 million in 2006. The impairment charge in 2006 related to amortized leasehold costs associated with individually insignificant unproved properties.

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

	Three Months Ended September 30,	
	2006	**2005**
General and administrative expenses	$ 15,680	$ 9,353
Reimbursements and allocations	(5,645)	(2,609)
General and administrative expenses, net	$ 10,035	$ 6,744

General and administrative expenses before reimbursements and allocations increased $6.3 million to $15.7 million during the third quarter of 2006. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $3.5 million and an increase in the current year accrual for cash payments under our Production Participation Plan of $1.3 million. Personnel salary expenses were higher in 2006 due to an increase in our employee base resulting from our continued growth. The increased cost of the Production Participation Plan was caused primarily by higher 2006 production volumes and higher average sales prices between periods. The increase in reimbursements and allocations was caused by a higher number of operated properties due to recent acquisitions and drilling activities during the fourth quarter of 2005 and first three quarters of 2006. Our net general and administrative expenses on a BOE basis increased 13% between periods from $2.29 to $2.58. As a percentage of oil and natural gas sales, our net general and administrative expenses increased from 4% during the third quarter of 2005 to 5% during the third quarter of 2006.

Change in Production Participation Plan Liability. For the third quarter, this non-cash expense increased $0.2 million over the same period in 2005. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2007 under our Production Participation Plan. Although payments take place over the life of oil and gas properties contributed to the Plan, some properties for over 20 years, we must expense the present value of estimated future payments over the Plan s five year vesting period. The increase in expense primarily reflects changes to future cash flow estimates due to the effect of a sustained higher price environment and recent acquisitions, as well as employees continued vesting in the Plan. Assumptions that are used to calculate this liability are subject to estimation and will vary from period to period based on the current market for oil and natural gas prices, discount rates and overall market conditions.

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

	Three Months Ended September 30,	
	2006	**2005**
Credit Agreement	$ 5,710	$ 3,485
Senior Subordinated Notes	11,177	6,439
Amortization of debt issue costs and debt discount	1,291	1,058
Accretion of tax sharing liability	498	620
Other	300	38
Capitalized interest	(97)	
Total interest expense	$ 18,879	$ 11,640

The increase in interest expense was mainly due to the October 2005 issuance of $250.0 million of 7% Senior Subordinated Notes due 2014 and additional borrowings outstanding under our credit agreement.

Our weighted average debt outstanding during the third quarter of 2006 was $952.8 million versus $627.6 million in the third quarter of 2005. Our weighted average effective cash interest rate was 7.2% during the third quarter of 2006 versus 6.3% during the third quarter of 2005. 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 7.7% during the third quarter of 2006 versus 7.0% during the third quarter of 2005.

Income Tax Expense. Income tax expense totaled $19.3 million for the third quarter of 2006 and $20.9 million for the third quarter of 2005. Our effective income tax rate decreased from 38.6% for the third quarter of 2005 to 28.0% for the third quarter of 2006 due to the recognition of a $1.8 million deferred tax benefit for 2005 enhanced oil recovery (EOR) tax credits, a $2.3 million benefit relating to a true-up of our effective rate to our 2005 state returns as filed, a deferred tax benefits of $0.5 million as a result of recently enacted tax legislation in Michigan, and other one time expense items.

The current portion of income tax was a benefit of $4.1 million for the quarter ended September 30, 2006 compared to current income tax expense of $4.4 million in the same period in 2005, mainly due to one-time benefits for a true-up of our effective tax rate to our 2005 state returns. In the third quarter of 2006, we reported a tax loss on our 2005 federal return as filed, primarily due to intangible drilling deductions allowed, which resulted in a federal tax refund of $4.7 million.

Net Income. Net income increased from $33.3 million during the third quarter of 2005 to $49.5 million during the third quarter of 2006. The primary reasons for this increase included a 32% increase in equivalent volumes sold and 18% higher oil and gas prices net of hedging between periods as well as certain income tax benefits recognized during the third quarter of 2006, which were partially offset by higher lease operating expense, production taxes, DD&A, exploration and impairment, general and administrative, Production Participation Plan, interest expenses, and income taxes resulting from our continued growth.

Liquidity and Capital Resources

Overview. At December 31, 2005, our debt to total capitalization ratio was 46.4%, we had $10.4 million of cash on hand and $997.9 million of stockholders equity. At September 30, 2006, our debt to total capitalization ratio was 44.9%, we had $3.8 million of cash on hand and $1,155.6 million of stockholders equity. In the first three quarters of 2006, we generated $351.9 million from operating activities, an increase of $140.7 million over the same period in 2005. Cash provided by operating activities increased primarily because of higher production from our recent acquisitions, successful drilling activities and higher average sales prices, and was partially offset by higher operating costs. We also generated $70.2 million from financing activities primarily consisting of $70.0 million in net borrowings against our credit facility. Cash on hand and cash flows from operating and financing activities were primarily used to finance $349.5 million of drilling capital expenditures paid in the first nine months, $79.2 million of cash acquisition capital expenditures to acquire the Michigan Properties, the central Utah Hingeline unproved acreage, tubulars, other unproved property leaseholds and the pipeline in the Postle field, $40.7 million in interest payments, and $12.1 million in payments under the Production Participation Plan. The chart below details our drilling capital expenditures incurred by region during the first nine months of 2006 (in thousands):

	Drilling Capex	% of Total
Permian Basin	$ 144,836	42%
Rocky Mountains	94,728	28%
Mid-Continent	62,060	18%
Gulf Coast	32,446	10%
Michigan	7,629	2%
Total drilling capital expenditures incurred	341,699	100%
Decrease in accrued capital expenditures	7,824	
Total drilling capital expenditures paid	$ 349,523	

We continually evaluate our capital needs and compare them to our capital resources. Our 2006 budgeted capital expenditures for the further development of our property base ranges from $420.0 million to $440.0 million, an increase from the $223.6 million incurred on capitalized development during 2005. Although we have no specific budget for property acquisitions in 2006, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund our additional 2006 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $440.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional equity or agreements with industry partners. Our level of capital 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.

Credit Agreement. Whiting Oil and Gas Corporation has a $1.2 billion credit agreement with a syndicate of banks that, as of September 30, 2006, had a borrowing base of $800.0 million with $330.0 million outstanding leaving $470.0 million of available borrowing capacity. In October 2006, our syndicate of banks approved an increase in the borrowing base under the credit agreement to $875.0 million, effective November 1, 2006.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas Corporation may, throughout the term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect from time to time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas Corporation or other designated subsidiaries of ours from time to time in an aggregate amount not to exceed $50.0 million. As of September 30, 2006, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues, at Whiting Oil and Gas Corporation s 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 Corporation 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. As of September 30, 2006, the interest rate on the entire outstanding principal balance under the credit agreement was 6.4%.

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 (as defined in the credit agreement) ratio 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 Corporation and our wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions or other payments to us. 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 September 30, 2006. The credit agreement is secured by a first lien on all of Whiting Oil and Gas Corporation s properties included in the borrowing base for the credit agreement. We and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement. We have pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for our guarantee, and Equity Oil Company has mortgaged all of its properties 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.

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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. The indentures governing the notes contain restrictive covenants that may limit our and our subsidiaries 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. In addition, Whiting Oil and Gas Corporation s credit agreement restricts the ability of our subsidiaries to make certain payments, including principal on the notes, to us. We were in compliance with these covenants as of September 30, 2006. Three of our 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 Securities and Exchange Commission 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.

Tax Separation and Indemnification Agreement with Alliant Energy. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with Alliant Energy, our former parent company. Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax bases of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax bases of our assets. The additional 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. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in bases not occurred. In 2014, we will be obligated to pay Alliant Energy 90% of the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. During 2005, we made a payment of $5.1 million under this agreement. During the first nine months of 2006, we did not make any payments under this agreement but did recognize $1.5 million of accretion expense, which is included as a component of interest expense. Our estimate of payments to be made under this agreement of $4.1 million in 2006 was reflected as a current liability at September 30, 2006.

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of September 30, 2006 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include asset retirement obligations or Production Participation Plan liabilities since we

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cannot determine with accuracy the timing of future payments. This table also does not include interest expense under Whiting Oil and Gas Corporation s credit agreement since this is a floating rate instrument and we cannot determine with accuracy the timing of future loan advances and repayments or interest rates.

		Payments due by period (in thousands)			
Contractual Obligations	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**More than 5 years**
Long-term debt (a)	$ 945,169	$	$	$ 330,000	$ 615,169
Cash interest expense on notes (b)	307,717	44,517	89,034	89,034	85,132
Purchase obligations (c)	312,977	16,355	92,722	103,537	100,363
Drilling rig contracts (d)	22,712	14,643	5,988	2,081	
Derivative contract liability fair value (e)	12,583	2,782	9,801		
Operating leases (f)	6,281	1,709	2,981	1,591	
Tax Separation and Indemnification Agreement with Alliant Energy (g)	30,378	4,057	6,710	5,433	14,178
Total	$ 1,637,817	$ 84,063	$ 207,236	$ 531,676	$ 814,842

(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 7.6% until the due date of the instrument.

(c) 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 eight 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 or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. As calculated on an annual basis, our failure to purchase the minimum CO_2 volumes requires us to pay the suppliers for any deficiency. 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.

(d) We entered into three separate three-year agreements in 2005 for rigs drilling in the Rocky Mountains region and a two-year agreement in February 2006 for a rig drilling in North Dakota. As of September 30, 2006, early termination of these contracts would have required maximum penalties of $16.6 million. No other drilling rigs working for us are currently under long-term contracts or contracts which cannot be terminated at the end of the well that is currently being drilled. Due to their short-term nature and the 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.

(e) We have entered into derivative contracts, primarily costless collars, to hedge our exposure to oil and gas price fluctuations. As of September 30, 2006, the forward price curves for oil and gas generally exceeded the price curves that were in effect when these contracts were entered into, resulting in a derivative fair value current liability of $2.8 million and long-term liability of $9.8 million. 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. See Critical Accounting Policies and Estimates-Hedging in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 and Item 3, Quantitative and Qualitative Disclosures About Market Risk in this Quarterly Report on Form 10-Q for additional information regarding our derivative obligations.

(f) 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 23,000 square feet of office space in Midland, Texas through February 28, 2008.

(g) Amounts shown are estimates based on estimated future income tax benefits from the increase in tax bases described under Tax Separation and Indemnification Agreement with Alliant Energy above.

Price-sharing Arrangement. As part of a 2002 purchase transaction, we agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result of the escalation clause, the sharing amount at January 1, 2006 increased to 50% of the actual price received in excess of $20.56 per barrel. As of September 30, 2006, approximately 42,100 net barrels of crude oil per month (5% of September 2006 net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the first nine months of 2006, we paid $7.0 million under this agreement. As of September 30, 2006, we have accrued an additional $0.9 million as currently payable.

New Accounting Policies

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment* (SFAS 123R). This Statement is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and its related implementation guidance. SFAS 123R requires a company to measure the grant date fair value of equity awards given to employees in exchange for services and recognize that cost, less estimated forfeitures, over the period that such services are performed. Prior to adopting SFAS 123R, the Company accounted for stock-based compensation under SFAS 123, whereby the Company s policy was to recognize actual forfeitures of restricted stock only when they occurred rather than estimate them at the grant date and subsequently true-up estimated forfeitures to actuals. SFAS 123R requires companies to include forfeitures as part of the grant date estimate of compensation cost. We adopted SFAS 123R on January 1, 2006 using the modified prospective transition method. In accordance with the modified prospective method, prior period results have not been restated.

The adoption of SFAS 123R had a minimal impact on income before income taxes and net income, and had no effect on basic or diluted earnings per share, for the three and nine months ended September 30, 2006, as presented in the our consolidated statements of income.

New Accounting Pronouncements

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The adoption of FIN 48 is not expected to have a material impact on our consolidated financial position or results of operations. The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. 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 the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The interpretation is effective for fiscal years beginning after December 15, 2006.

In September 2006, the FASB issued Statement No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132R* (SFAS 158). The adoption of SFAS 158 is not expected to have a material impact on our consolidated financial position or results of operations, as we do not currently have

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any defined benefit pension or other postretirement plans. SFAS 158 requires companies to recognize in their balance sheets an asset for a plan s overfunded status or a liability for a plan s underfunded status, measure a plan s assets and its obligations that determine its funded status as of the date of their fiscal year-end, and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. Those changes will be reported in comprehensive income and as a separate component of stockholders equity. Additional footnote disclosures will also be required. SFAS 158 is effective for fiscal years ending after December 15, 2006.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). The adoption of SAB 108 is not expected to have a material impact on our consolidated financial position or results of operations. SAB 108 provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 is effective for fiscal years ending on or after November 15, 2006, allowing a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006, for errors that were not previously deemed material, but are material under the guidance in SAB 108.

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, 2005.

Effects of Inflation and Pricing

We experienced increased costs during 2005 and the first nine months of 2006 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. 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.

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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, 2005 and have not materially changed since that report was filed.

Our outstanding hedges as of October 16, 2006 are summarized below:

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	NYMEX Floor/Ceiling
Crude Oil	10/2006 to 12/2006	125,000	$ 45.00/$81.10
Crude Oil	10/2006 to 12/2006	215,000	$ 50.00/$72.05
Crude Oil	10/2006 to 12/2006	110,000	$ 50.00/$74.30
Crude Oil	01/2007 to 03/2007	125,000	$ 45.00/$81.00
Crude Oil	01/2007 to 03/2007	215,000	$ 50.00/$70.90
Crude Oil	01/2007 to 03/2007	110,000	$ 50.00/$73.15
Crude Oil	04/2007 to 06/2007	110,000	$ 50.00/$72.00
Crude Oil	04/2007 to 06/2007	300,000	$ 50.00/$78.50
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	04/2008 to 06/2008	110,000	$ 48.00/$71.60
Crude Oil	07/2008 to 09/2008	110,000	$ 48.00/$70.85
Crude Oil	10/2008 to 12/2008	110,000	$ 48.00/$70.20
Natural Gas	10/2006 to 12/2006	600,000	$ 6.00/$12.28
Natural Gas	10/2006 to 12/2006	1,000,000	$ 6.00/$12.18
Natural Gas	01/2007 to 03/2007	600,000	$ 6.00/$15.20
Natural Gas	01/2007 to 03/2007	1,000,000	$ 6.00/$15.52

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the 2006 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 of $1.4 million for the remainder of 2006. For the 2006 natural gas contracts listed above, a hypothetical $0.10 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the gain (loss) on hedging activities of $0.5 million for the remainder of 2006.

We have also entered into fixed price marketing contracts directly with end users for a portion of the natural gas we produce in Michigan. All of those contracts have built-in pricing escalators of 4% per year. Our outstanding fixed price marketing contracts at October 16, 2006 are summarized below:

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Commodity	Period	Monthly Volume (MMBtu)	2006 Price Per MMBtu
Natural Gas	01/2002 to 12/2011	51,000	$ 4.57
Natural Gas	01/2002 to 12/2012	60,000	$ 4.05

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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 the end of the quarter ended September 30, 2006. Based upon their evaluation of these disclosures 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 the end of the quarter ended September 30, 2006 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 September 30, 2006 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 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2005. No material change to such risk factors has occurred during the nine months ended September 30, 2006.

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 31st day of October, 2006.

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.