CREDO PETROLEUM CORP
Form 10-Q
June 14, 2006

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

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended April 30, 2006

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: 0-8877
CREDO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Colorado	**84-0772991**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1801 Broadway, Suite 900, Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

303-297-2200

(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 o No þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Act.)

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, net of treasury stock, as of the latest practicable date.

Date	Class	Outstanding
June 12, 2006	Common stock, $.10 par value	9,213,553

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Quarterly Report on Form 10-Q For the Period Ended April 30, 2006
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The terms CREDO , Company , we , our , and us refer to CREDO Petroleum Corporation and its subsidiaries unle context suggests otherwise.

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets

	April 30, 2006 *(Unaudited)*	October 31, 2005
A S S E T S		
Current Assets:		
Cash and cash equivalents	**$ 2,084,000**	$ 1,935,000
Short-term investments	**5,893,000**	5,495,000
Receivables:		
Accrued oil and gas sales	**2,929,000**	2,776,000
Trade	**816,000**	1,003,000
Other current assets	**257,000**	245,000
Total current assets	**11,979,000**	11,454,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**4,864,000**	3,452,000
Evaluated oil and gas properties	**40,049,000**	36,121,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(16,594,000)**	(15,022,000)
Net oil and gas properties, at cost, using full cost method	**28,319,000**	24,551,000
Exclusive license agreement, net of amortization of $396,000 in 2006 and $361,000 in 2005	**303,000**	338,000
Compressor and tubular inventory to be used in development	**1,263,000**	1,288,000
Other assets	**217,000**	213,000
Total assets	**$ 42,081,000**	$ 37,844,000
L I A B I L I T I E S A N D S T O C K H O L D E R S E Q U I T Y		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 2,787,000**	$ 3,426,000
Income taxes payable	**359,000**	331,000
Total current liabilities	**3,146,000**	3,757,000

Long Term Liabilities:		
Deferred income taxes, net	**6,781,000**	5,978,000
Exclusive license obligation, less current obligations of $64,000 in 2006 and 2005	**233,000**	233,000
Asset retirement obligation	**909,000**	929,000
Total liabilities	**11,069,000**	10,897,000
Commitments		
Stockholders Equity:		
Preferred stock, no par value, 5,000,000 shares authorized, none issued		
Common stock, $.10 par value, 20,000,000 shares authorized, 9,510,000 shares issued in 2006 and 2005	**951,000**	951,000
Capital in excess of par value	**14,480,000**	13,933,000
Treasury stock, 297,000 shares in 2006 and 393,000 in 2005		(125,000)
Accumulated other comprehensive income (loss)		(306,000)
Retained earnings, net of $6,272,000 related to 20% stock dividend in 2003	**15,581,000**	12,494,000
Total stockholders equity	**31,012,000**	26,947,000
Total liabilities and stockholders equity	**$ 42,081,000**	$ 37,844,000

The accompanying notes are an integral part of these consolidated financial statements.

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
(Unaudited)

	Six Months Ended April 30,		Three Months Ended April 30,	
	2006	2005	**2006**	2005
REVENUES:				
Oil and gas sales	**$ 7,843,000**	$ 5,389,000	**$ 3,723,000**	$ 3,004,000
Investment income and other	**443,000**	96,000	**198,000**	34,000
	8,286,000	5,485,000	**3,921,000**	3,038,000
COSTS AND EXPENSES:				
Oil and gas production	**1,743,000**	1,130,000	**739,000**	642,000
Depreciation, depletion and amortization	**1,629,000**	1,042,000	**891,000**	565,000
General and administrative	**579,000**	540,000	**319,000**	255,000
Interest	**18,000**	19,000	**9,000**	10,000
	3,969,000	2,731,000	**1,958,000**	1,472,000
INCOME BEFORE INCOME TAXES	**4,317,000**	2,754,000	**1,963,000**	1,566,000
INCOME TAXES	**(1,230,000)**	(771,000)	**(571,000)**	(439,000)
NET INCOME	**$ 3,087,000**	$ 1,983,000	**$ 1,392,000**	$ 1,127,000
EARNINGS PER SHARE OF COMMON STOCK BASIC	**$ .34**	$ .22	**$ .15**	$ .12
EARNINGS PER SHARE OF COMMON STOCK DILUTED	**$ .33**	$ .21	**$ .15**	$ .12
Weighted average number of shares of Common Stock and dilutive securities:				
Basic	**9,171,000**	9,059,000	**9,207,000**	9,063,000
Diluted	**9,498,000**	9,305,000	**9,506,000**	9,319,000

The
accompanying

notes are an
integral part of
these
consolidated
financial
statements.

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Statement of Stockholders Equity and Comprehensive Income (Loss)
(Unaudited)
For the Six Months Ended April 30, 2006

	Common Stock		Capital In Excess Of	Treasury	Accumulated Other Comprehensive Income (Loss)	Comprehensive	Retained	Total Stockholders
	Shares	Amount	Par Value	Stock		Income	Earnings	Equity
Balance, October 31, 2005	9,510,000	$ 951,000	$ 13,933,000	$ (125,000)	$ (306,000)		$ 12,494,000	$ 26,947,000
Comprehensive income:								
Net income						$ 3,087,000	3,087,000	3,087,000
Other comprehensive income:								
Change in fair value of derivatives, net of tax					306,000	306,000		306,000
Total comprehensive income						$ 3,393,000		
Exercise of common stock options			428,000	125,000				553,000
Compensation expense associated with unvested portion of previously granted stock options			119,000					119,000
Balance, April 30, 2006	9,510,000	$ 951,000	$ 14,480,000	$	$		$ 15,581,000	$ 31,012,000

The accompanying notes are an

integral part of these consolidated financial statements.

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended April 30,	
	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	**$ 3,087,000**	$ 1,983,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**1,629,000**	1,042,000
Deferred income taxes	**803,000**	833,000
Compensation expense related to stock options granted	**119,000**	147,000
Other		30,000
Changes in operating assets and liabilities:		
Proceeds from short-term investments	**193,000**	2,349,000
Purchase of short-term investments	**(591,000)**	(987,000)
Accrued oil and gas sales	**(153,000)**	(527,000)
Trade receivables	**187,000**	86,000
Other current assets	**294,000**	273,000
Accounts payable and accrued liabilities	**(639,000)**	(1,178,000)
Income taxes payable	**28,000**	(34,000)
NET CASH PROVIDED BY OPERATING ACTIVITIES	**4,957,000**	4,017,000
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and gas properties	**(5,536,000)**	(3,454,000)
Proceeds from sale of oil and gas properties	**174,000**	
Changes in other long-term assets	**1,000**	(167,000)
NET CASH USED IN INVESTING ACTIVITIES	**(5,361,000)**	(3,621,000)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from exercise of stock options	**553,000**	53,000
Purchase of treasury stock		(8,000)
NET CASH PROVIDED BY FINANCING ACTIVITIES	**553,000**	45,000
INCREASE IN CASH AND CASH EQUIVALENTS	**149,000**	441,000
CASH AND CASH EQUIVALENTS:		
Beginning of period	**1,935,000**	518,000

End of period	**$**	**2,084,000**	$	959,000
Supplemental cash flow information:				
Cash paid during the period for income taxes	**$**	**486,000**	$	
Cash paid during the period for interest	**$**		$	

The accompanying notes are an integral part of these consolidated financial statements.

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Notes To Consolidated Financial Statements (Unaudited)
April 30, 2006

1. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with U. S. generally accepted accounting principles for interim financial information and with the instructions for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by U. S. generally accepted accounting principles for complete financial statements. In the opinion of management, the consolidated financial statements contain all adjustments (consisting of normal recurring adjustments) considered necessary for a fair presentation of the company s results for the periods presented. These consolidated financial statements should be read in conjunction with the company s Annual Report on Form 10-K for the fiscal year ended October 31, 2005.

The company effected a three-for-two stock split in the third fiscal quarter of 2005. All share and per share amounts discussed and disclosed in this Quarterly Report on Form 10-Q reflect the effect of that stock split.

Certain financial statement amounts have been reclassified to conform to the presentation used for the 2006 periods. Effective with the second quarter of 2006, the company has reclassified reimbursed overhead from operating revenue to general and administrative expense. For the six months ended April 30, 2006 and 2005 the reclassified amounts were $355,000 and $323,000, respectively and for the three months ended April 30, 2006 and 2005 the reclassified amounts were $182,000 and $164,000 respectively.

2. SIGNIFICANT ACCOUNTING POLICIES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The company bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the company believes that its estimates are reasonable and that actual results will not vary significantly from the estimated amounts.

3. STOCK-BASED COMPENSATION

The company currently has one stock-based employee compensation plan, which is described in the Notes to Consolidated Financial Statements in the company s Annual Report on Form 10-K for the year ended October 31, 2005. Prior to November 1, 2005, the company accounted for this plan under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Statement of Financial Accounting Standards (SFAS) No. 123, Accounting for Stock-Based Compensation. No stock-based employee compensation expense was recognized in the company s Consolidated Statement of Operations prior to November 1, 2005, as all options granted under the company s stock-based compensation plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective November 1, 2005, the company adopted the fair value recognition provisions of SFAS No. 123 (R), Share Based Payment, using the modified-retrospective-transition method. Under this transition method, the company restated the results of all prior periods back to the beginning of fiscal 1997 (the fiscal year of inception for this stock-based compensation plan) in accordance with the original provisions of SFAS No. 123. The cumulative effect of this restatement was an increase of $1,447,000 to capital in excess of par value and a decrease to retained earnings in the same amount. For the six months ended April 30, 2006 and 2005, the company recognized compensation expense related to its stock option plan of $119,000 and $147,000, respectively and for the three months ended April 30, 2006 and 2005, the company recognized compensation expense of $59,000 and $74,000, respectively. The company has not made any option grants during fiscal 2006. The fair value of the 33,750 options granted during the six months ended April 30, 2005 was estimated as of the grant date using the Black-Scholes option pricing model with the following assumptions: volatility, 48%; expected option term, 5 years; risk-free interest rate, 3.7% and; expected

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dividend yield, 0%. If option grants are made in the future, compensation expense for all such share-based payments granted, based upon the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R) will also be included in compensation expense.

Plan activity for the six months ended April 30, 2006 is set forth below and has been adjusted for the 3-for-2 stock splits in fiscal 2005 and 2004 and the 20% stock dividend in 2003.

	Six Months Ended April 30, 2006	
	Number of Options	Weighted Average Exercise Price
Outstanding at October 31, 2005	485,064	$ 5.78
Granted		
Exercised	(96,158)	5.75
Cancelled or forfeited	(937)	5.93
Outstanding at April 30, 2006	387,969	$ 5.79
Exercisable at April 30, 2006	259,222	$ 5.70
Weighted average contractual life at April 30, 2006		7.15

The following table summarizes information about stock options currently outstanding and exercisable at April 30, 2006:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding at April 30, 2006	Weighted Average Remaining Contractual Life in Year	Weighted Average Exercise Price	Number Exercisable at April 30, 2006	Weighted Average Exercise Price
$3.09-$3.72	54,750	6.48	$ 3.56	25,313	$ 3.59
$5.93-$8.93	333,219	7.26	$ 6.16	233,909	$ 5.93
$3.09-$8.93	387,969	7.15	$ 5.79	259,222	$ 5.70

Total estimated unrecognized compensation cost from unvested stock options as of April 30, 2006 was approximately $287,000, which is expected to be recognized over an average period of approximately 1.1 years.

4. NATURAL GAS PRICE HEDGING

The company periodically hedges the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Hedging transactions typically take the form of forward short positions and collars on the NYMEX futures market, and are closed by purchasing offsetting positions. Such hedges,

which are accounted for as cash flow hedges, do not exceed estimated production volumes, are expected to have reasonable correlation between price movements in the futures market and the cash markets where the company s production is located, and are authorized by the company s Board of Directors. Hedges are expected to be closed as related production occurs but may be closed earlier if the anticipated downward price movement occurs or if the company believes that the potential for such movement has abated.
The company recognizes all derivatives (consisting solely of cash flow hedges) on the balance sheet at fair value at the end of each period. Changes in the fair value of a cash flow hedge are recorded in Stockholders Equity as Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheets and then are reclassified into the Consolidated Statement of Operations as the underlying hedged item affects earnings. Amounts reclassified into earnings related to natural gas hedges are included in oil and gas sales.

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Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had after tax hedging losses of $190,000 in the first six months of 2006 and after tax hedging losses of $202,000 for the same period in 2005. Any hedge ineffectiveness, which was not material for the first six months of 2006, is immediately recognized in gas sales. The company currently has no open hedge positions.

The company has a hedging line of credit with its bank which is available, at the discretion of the company, to meet margin calls. To date, the company has not used this facility and maintains it only as a precaution related to possible margin calls. The maximum credit line is $2,000,000 with interest calculated at the prime rate. The facility is unsecured and has affirmative covenants which require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company s bank, and prohibits unfunded debt in excess of $500,000. The hedging line of credit expires on October 31, 2006.

5. COMPREHENSIVE INCOME

Comprehensive income includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The components of comprehensive income for the three and six months ended April 30, 2006 and 2005 are as follows:

	Six Months Ended April 30,		Three Months Ended April 30,	
	2006	2005	**2006**	2005
Net income	**$ 3,087,000**	$ 1,983,000	**$ 1,392,000**	$ 1,127,000
Other comprehensive income:				
Change in fair value of derivatives	**425,000**	560,000		(46,000)
Income tax expense	**(119,000)**	(164,000)		13,000
Total comprehensive income	**$ 3,393,000**	$ 2,379,000	**$ 1,392,000**	$ 1,094,000

6. EARNINGS PER SHARE

The company s calculation of earnings per share of common stock is as follows:

	Six Months Ended April 30,					
	2006			2005		
	Net Income	**Shares**	**Net Income Per Share**	Net Income	Shares	Net Income Per Share
Basic earnings per share	**$ 3,087,000**	**9,171,000**	**$ .34**	$ 1,983,000	9,059,000	$ .22
Effect of dilutive shares of common stock from stock options		**327,000**	**(.01)**		246,000	(.01)
Diluted earnings per share	**$ 3,087,000**	**9,498,000**	**$ .33**	$ 1,983,000	9,305,000	$ .21

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	Three Months Ended April 30,					
	2006			2005		
	Net Income	**Shares**	**Net Income Per Share**	Net Income	Shares	Net Income Per Share
Basic earnings per share	**$ 1,392,000**	**9,207,000**	**$ .15**	$ 1,127,000	9,063,000	$ .12
Effect of dilutive shares of common stock from stock options		**299,000**			256,000	
Diluted earnings per share	**$ 1,392,000**	**9,506,000**	**$ .15**	$ 1,127,000	9,319,000	$ .12

7. INCOME TAXES

The company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time.

The total future deferred income tax liability is extremely complicated for any energy company to estimate due in part to the long-lived nature of depleting oil and gas reserves and variables such as product prices. Accordingly, the liability is subject to continual recalculation, revision of the numerous estimates required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

8. COMPRESSOR AND TUBULAR INVENTORY

Compressor and tubular inventory are finished goods, recorded at cost, which are expected to be used in the future development of certain of the Company s oil and gas properties. The Company has classified this amount as a long-term asset because the compressors and tubulars are not held for re-sale and the cost, net of amounts billed to joint interest owners in the normal course of business, will eventually be included in evaluated properties.

9. UNEVALUATED OIL AND GAS PROPERTIES

Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until they are evaluated. The following table shows, by category of cost and date incurred, the unevaluated oil and gas property costs excluded from the amortization computation as of April 30, 2006:

Net Costs Incurred During Periods Ended:	Exploration Costs	Development Costs	Acquisition Costs	Total Unevaluated Properties
April 30, 2006	$ 264,000	$ 232,000	$ 1,508,000	$ 2,004,000
October 31, 2005	176,000	145,000	2,094,000	2,415,000
October 31, 2004			445,000	445,000
	$ 440,000	$ 377,000	$ 4,047,000	$ 4,864,000

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10. COMMITMENTS

Effective January 1, 2005, the company entered into an exploration agreement to generate and market gas drilling prospects in South Texas. The company is currently committed to spend $2,050,000 over two years primarily for seismic, leases and administrative costs. Through April 30, 2006, the company has made payments of $1,570,000 towards this commitment. In general, all costs incurred by the company are allocated over a number of prospects, and payout is calculated on a prospect by prospect basis based on recovery of the cost allocated to each prospect. The company owns 75% of each generated prospect before payout and 37.5% after payout. The company has the option to participate in each prospect for all, or a portion, of its interest. If the company does not participate for the full interest, the remaining amount will be sold to industry participants on a promoted basis. Drilling of generated prospects is not covered by the agreement. The company s drilling cost, if any, will depend upon its election to participate with, or sell, all or a portion of its interest in any prospect generated.

In April 2005, the company committed approximately $1,200,000 over an expected two-year period to purchase a 30% interest in 18,000 gross acres along the Central Kansas Uplift, in Graham and Sheridan counties, Kansas, participate in a 3-D seismic survey, and drill five exploratory wells. Through April 30, 2006, the company has made payments of $847,000 towards this commitment. Subsequent drilling will be determined by results from the initial wells. Approximately 28 square miles of proprietary 3-D seismic will be shot to define Lansing-Kansas City oil prospects at about 4,000 feet.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes certain statements that may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements included in this Quarterly Report on Form 10-Q, other than statements of historical facts, address matters that the company reasonably expects, believes or anticipates will or may occur in the future. Forward-looking statements may relate to, among other things:

- the company s future financial position, including working capital and anticipated cash flow;
- amounts and nature of future capital expenditures;
- operating costs and other expenses;
- wells to be drilled or reworked;
- oil and natural gas prices and demand;
- existing fields, wells and prospects;
- diversification of exploration;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- the company s business strategy;

production of oil and natural gas;

matters related to the Calliope Gas Recovery System;

effects of federal, state and local regulation;

insurance coverage;

employee relations;

investment strategy and risk; and

expansion and growth of the company s business and operations.

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LIQUIDITY AND CAPITAL RESOURCES

At April 30, 2006, working capital was $8,833,000, compared to $7,296,000 at April 30, 2005. For the six months ended April 30, 2006, net cash provided by operating activities increased $940,000, or 23%, to $4,957,000 when compared to net cash provided by operating activities of $4,017,000 for the same period in 2005. This increase is primarily the result of increases in net income and other non-cash items of $1,603,000; a net increase of $398,000 in short term investments in 2006 versus a net decrease in short term investments of $1,362,000 in 2005 which resulted in a net decrease in cash provided by operating activities of $1,760,000 between the two periods; a net increase in cash provided by operating activities as a result of changes in accrued oil and gas sales, trade receivables and other current assets of $496,000; and a net increase in cash provided by operating activities as a result of changes in accounts payable and income taxes payable of $601,000. For the six months ended April 30, 2006 and 2005, net cash used in investing activities was $5,361,000 and $3,621,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $5,536,000 and $3,454,000, respectively.

The average return on the company s investments for the six months ended April 30, 2006 and 2005 was 6.5% and 1.4%, respectively. At April 30, 2006, approximately 55% of the investments were directly invested in mutual funds and were managed by professional money managers. Remaining investments are in managed partnerships that use various strategies to minimize their correlation to stock market movements. Most of the investments are highly liquid and the company believes they represent a responsible approach to cash management. In the company s opinion, the greatest investment risk is the potential for negative market impact from unexpected, major adverse news.

Existing working capital and anticipated cash flow are expected to be sufficient to fund operations and capital commitments for at least the next 12 months. As discussed in Note 10 to the consolidated financial statements, at April 30, 2006 the company had remaining commitments of $833,000 related to projects in South Texas and along the Central Kansas uplift. Such costs, which include overhead, lease bonuses, land services and 3-D seismic, are expected to be funded over the next six to nine months. At April 30, 2006, the company had no lines of credit or other bank financing arrangements except for the hedging line of credit discussed in Note 4. Because earnings are anticipated to be reinvested in operations, cash dividends are not expected to be paid. The company has no defined benefit plans and no obligations for post retirement employee benefits.

The company s earnings before interest, taxes, depreciation, depletion and amortization, (EBITDA) increased to $5,964,000 for the six months ended April 30, 2006 from $3,815,000 for the six months ended April 30, 2005. EBITDA is not a GAAP measure of operating performance. The Company uses this non-GAAP performance measure primarily to compare its performance with other companies in the industry that make a similar disclosure. The company believes that this performance measure may also be useful to investors for the same purpose. Investors should not consider this measure in isolation or as a substitute for operating income, or any other measure for determining the company s operating performance that is calculated in accordance with GAAP. In addition, because EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures employed by other companies. A reconciliation between EBITDA and net income is provided in the table below:

	Six Months Ended April 30,	
	2006	2005
RECONCILIATION OF EBITDA:		
Net Income	$ 3,087,000	$ 1,983,000
Add Back:		
Interest Expense	18,000	19,000
Income Tax Expense	1,230,000	771,000
Depreciation, Depletion and Amortization Expense	1,629,000	1,042,000
EBITDA	$ 5,964,000	$ 3,815,000

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OFF-BALANCE SHEET FINANCING

The company has no off-balance sheet financing arrangements at April 30, 2006.

PRODUCT PRICES AND PRODUCTION

Although product prices are key to the company s ability to operate profitably and to budget capital expenditures, they are beyond the company s control and are difficult to predict. Since 1991, the company has periodically hedged the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Hedging transactions typically take the form of forward short positions and collars on the NYMEX futures market, and are closed by purchasing offsetting positions. Such hedges, which are accounted for as cash flow hedges, do not exceed estimated production volumes, are expected to have reasonable correlation between price movements in the futures market and the cash markets where the company s production is located, and are authorized by the company s Board of Directors. Hedges are expected to be closed as related production occurs but may be closed earlier if the anticipated downward price movement occurs or if the company believes that the potential for such movement has abated. Refer to Note 4 to the Consolidated Financial Statements for a complete discussion on the company s hedging activities.

Gas and oil sales volume and price realization comparisons for the indicated periods are set forth below. Price realizations include the sales price and the effect of hedging transactions.

	Six Months Ended April 30,					
	2006		2005		% Change	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**965,000**	**$ 6.91**(1)	842,000	$ 5.39(2)	+ 15%	+ 28%
Oil (bbls)	**19,800**	**$59.37**	19,500	$43.66	+ 2%	+ 36%

	Three Months Ended April 30,					
	2006		2005		% Change	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**528,000**	**$ 5.85**	460,000	$ 5.51(3)	+ 15%	+ 6%
Oil (bbls)	**10,300**	**$61.63**	10,500	$44.49	- 3%	+ 39%

(1) Includes $0.27 Mcf hedging loss.

(2) Includes $0.33 Mcf hedging loss.

(3) Includes $0.12 Mcf hedging loss.

OPERATIONS

During the second fiscal quarter the company continued to focus on its two core projects natural gas drilling and application of its patented Calliope Gas Recovery System.

During fiscal 2005, the company expanded into South Texas through an exploration program using 3-D seismic to define the Vicksburg, Frio, Queen and Wilcox prospects in Hidalgo and Jim Hogg counties and into north-central Kansas through an exploration program using 3-D seismic to define Lansing-Kansas City oil prospects in Graham and Sheridan counties. The company believes that, in combination, its drilling and Calliope projects provide an excellent (and possibly unique) balance for achieving its goal of adding long-lived natural gas reserves and production at reasonable costs and risks.

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The company will continue to actively pursue adding reserves through its two core projects in fiscal 2006 and expects these activities to be a reliable source of reserve additions. However, the timing and extent of such activities can be dependent on many factors which are beyond the company s control, including but not limited to, the availability of oil field services such as drilling rigs, production equipment and related services and access to wells for application of the company s patented liquid lift system on low pressure gas wells. The prevailing price of oil and natural gas has a significant affect on demand and, thus, the related cost of such services and wells.

The company is currently experiencing delays in securing drilling rigs and for the delivery of production equipment, primarily compressors and coil tubing. These delays are extending the time it takes the company to conduct its field operations. As a result, the company could be at risk for price increases related to these types of services and equipment.

Drilling Activities. The company currently drills primarily on its 60,000 gross acre inventory located along the northern shelf of the Anadarko Basin. Drilling expenditures were concentrated on the company s acreage inventory located along the northern shelf of the Anadarko Basin of Oklahoma. The wells targeted the Morrow, Oswego and Chester formations between 7,000 and 10,000 feet. A substantial number of additional wells are anticipated for the area.

Drilling is not restricted to the northern Anadarko shelf acreage. The company is generating prospects elsewhere in the Northern Anadarko Basin, in the Oklahoma Panhandle, north-central Oklahoma, north-central Kansas and South Texas.

In the first half of 2006, a series of six wells were drilled in Harper and Ellis Counties, Oklahoma. Three were dry holes and the other three were completed for production in February 2006. The three new producers are located on the company s 5,120 gross acre Glacier Prospect, the 2,560 gross acre Buffalo Creek Prospect, and the 1,280 gross acre Gage Prospect. The Glacier Prospect s 7,500-foot Garnet State #1-27 encountered two separate 10-foot Morrow sands. It was placed on production February 9, 2006 at an initial daily rate of 2.75 MMcfe (million cubic feet of gas equivalent). The well is currently producing at a daily rate of 4.3 MMcfe after equipment modifications were made to accommodate a higher flow rate. Flowing pressures have been steady (taking into account the significant production increase), indicating that this well is located in a significant reservoir. The company owns a 57% working interest and is the operator. The 6,900-foot Lauer #1-21 well was the sixth well drilled on the company s 2,560 gross acre Buffalo Creek Prospect. The Lauer commenced production on February 16, 2006, and has current daily production is approximately 60 BOE. In anticipation of additional drilling, a 3-D seismic program has been proposed on the Buffalo Creek Prospect to identify additional drilling locations. The company owns a 31% working interest.

Five additional wells are scheduled in the upcoming drilling round which commenced in mid-May. This drilling includes a north and an east offset to the recently completed Garnet State #1-27 and an east offset to the recently completed Lauer #1-21. Two wells have been drilled, however, the company has not released information on the results for proprietary business reasons.

During fiscal 2005, the company significantly expanded both the volume and breadth of its exploration program with new projects in South Texas and north-central Kansas. It is the company s intention to diversify its exploration geographically, scientifically, and in terms of capital, risk and reserve potential. Compared to drilling in Oklahoma, the South Texas project involves higher costs and greater risks but significantly higher per well reserve potential. The north-central Kansas project is geared to oil exploration and has excellent potential to add significant reserves at moderate costs and risks. Both projects are in areas where 3-D seismic is a proven exploration tool and where continuing refinements are providing excellent exploration success. Equally as important, both exploration teams specialize in their respective geographic areas and have been highly successful finding new reserves using 3-D seismic.

As previously discussed, drilling of generated South Texas prospects is not covered by the exploration agreement and, therefore, is not a capital requirement under the exploration agreement. Drilling is expected to commence in mid-2006. The initial four well drilling program is 3-D seismic driven and focuses on the Vicksburg, Frio, Queen and Wilcox sands in Hidalgo and Jim Hogg Counties ranging in depth from 10,000 to 15,000 feet. The 8/8ths cost to drill and complete a test well on all of the first four prospects is currently estimated to total approximately $16,000,000. The company elected to participate in the first well for its full 37.5% interest and drilling has commenced. If the company elects to participate for its full 37.5% interest in all four wells, the total cost to the company is estimated to be approximately $6,000,000.

The north-central Kansas project agreement provides for approximately 28 square miles of 3-D seismic to be collected and evaluated and five exploratory wells to be drilled. Completed costs for individual wells are estimated to be approximately $280,000.

In this Quarterly Report on Form 10-Q, the company is providing the following information to enhance and supplement the disclosures regarding Reserve Replacement Percentage and Finding Cost per Mcfe which are contained in its Annual Report on Form 10-K for the year ended October 31, 2005. The company will eliminate disclosure of Reserve Replacement Percentage and Finding Cost per Mcfe from its 1933 and 1934 Act filings, beginning with its Annual Report on Form 10-K for the fiscal year ending October 31, 2006, because the information is generally available from independent sources.

The company previously disclosed in its most recent Annual Report on Form 10-K that, during the fiscal year ended October 31, 2005 the company replaced 106% of the reserves produced in fiscal 2005. This reserve replacement percentage is derived directly from the line items disclosed in the reconciliation of beginning and ending proved reserve quantities contained in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 42 of the company s Annual Report on Form 10-K. The table below shows the calculation used by the company at October 31, 2005. Oil is converted to gas for the calculation of Mcfe (thousand cubic feet equivalent) on the basis of one barrel of oil is equal to six Mcf of gas.

	Year Ended October 31, 2005		
	Gas (Mcf)	**Oil (Bbls)**	**Total (Mcfe)**
Extensions and discoveries	2,962,000	22,000	3,094,000
Revisions of previous estimates	(889,000)	(6,000)	(925,000)
Total proved reserve additions	2,073,000	16,000	2,169,000
Production	1,830,000	37,000	2,052,000
Reserve replacement percentage			106%

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The company previously disclosed in its Annual Report on Form 10-K for the fiscal year ended October 31, 2005 that its finding cost for the period was $2.73 per Mcfe excluding start-up costs in South Texas and north-central Kansas. The Company believes that excluding these start-up costs provides a meaningful matching of current costs with current reserve additions. Finding costs are derived from the line item Total Including Asset Retirement Obligation disclosed in the table identifying Acquisition, Exploration and Development Costs Incurred contained in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 41 of the company s Annual Report on Form 10-K and from the line items disclosed in the reconciliation of beginning and ending proved reserve quantities contained in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 42 of the company s Annual Report on Form 10-K. The table below shows the calculation used by the company at October 31, 2005.

	October 31, 2005
Total Acquisition, Exploration and Development Costs Incurred Including Asset Retirement Obligation	$ 7,327,000
Less South Texas and north-central Kansas start-up costs	(1,401,000)
Net Acquisition, Exploration and Development Costs Incurred Including Asset Retirement Obligation	$ 5,926,000
Total Proved Reserve (Mcfe) Additions (see table above)	2,169,000
Finding Cost Per Mcfe	$ 2.73

Proved reserve additions, including the proved developed and proved undeveloped portions can be calculated from the information in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 42 of the company s Annual Report on Form 10-K. As is stated in Management s Discussion and Analysis of Financial Condition and Results of Operations, Oil and Gas Activities, Drilling Activities, and Calliope Gas Recovery System on pages 19 through 22 of the company s Annual Report on Form 10-K, these proved reserve additions for the fiscal year ended October 31, 2005 were primarily the result of activity on the company s two core projects, drilling along the shelf of the Northern Anadarko Basin in northwest Oklahoma and application of the company s patented liquid lift system on low pressure gas wells.

The company uses only proved reserves to calculate the reserve replacement percentage and finding costs described above and does not include any proved reserves attributable to consolidated entities or investments accounted for using the equity method.

The finding costs and production replacement measures are used by the company as one way of measuring the Company s performance and comparing it to that of its competitors and the industry. The calculation of both of these performance measures is based, in part, on estimated proved oil and gas reserve quantities. As is more fully described under Item 2., Properties, Significant Properties, Estimated Proved Oil and Gas reserves, and Future Net Revenues on pages 11 and 12 of the company s Annual Report on Form 10-K for the fiscal year ended October 31, 2005, estimates of reserve quantities must be viewed as being subject to significant change as more data about the company s properties becomes available. Additionally, both of these performance measures are historical in nature and are calculated as of a specific date and, may not be indicative of the company s future performance.

The company s success depends primarily on locating and producing new reserves, the level of production from existing wells, and prices of oil and natural gas. Production from the company s oil and gas properties declines over time. In order to maintain current production rates the company must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. In addition, competition for oil and gas leases, oil field services, and producing oil and gas properties is intense and many of the company s competitors have financial and other resources substantially greater than those available to it. Without success on its core projects, the company s reserves, production and revenues will decline rapidly.

All of the company s oil and natural gas properties are located on-shore in the continental United States. The company s future drilling activities may not be successful, and its overall drilling success rate may change. Unsuccessful drilling activities could have a material adverse effect on the company s results of operations and financial condition. Also, the company may not be able to obtain the right to drill in areas where it believes there is significant potential for the company.

Calliope Gas Recovery Technology. The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. Calliope can achieve substantially lower flowing bottom hole pressure than conventional production methods because it does not rely on reservoir pressure to lift liquids. Lower bottom hole pressure can translate into recovery of substantial additional natural gas reserves.

Calliope has proven to be reliable and flexible over a wide range of applications on wells the company owns and operates. It has also proven to be consistently successful. Accordingly, the company has recently begun implementing strategies designed to widen the envelope of wells on which Calliope should be installed.

Realizing Calliope s value continues to be a top priority of the company. The company is focused on three fronts to increase the number of Calliope installations: expanding the geographic region for purchasing Calliope candidate wells from third parties, joint ventures with larger companies, and drilling wells into low-pressure gas reservoirs for the purpose of using Calliope to recover stranded natural gas reserves.

Current natural gas prices have facilitated a new project to drill wells into low-pressure natural gas reservoirs. Many low-pressure reservoirs, including abandoned fields, contain substantial stranded natural gas that can be recovered by Calliope. This project is designed to ramp-up the number of Calliope installations, improve the company s control over monetizing Calliope s value, control configuration of wellbores for optimum Calliope performance, and broaden the range of reservoirs for Calliope applications. Completed well costs are estimated to be approximately $2,000,000 to $2,500,000 including installation of Calliope. The company expects to commence drilling wells for Calliope applications in mid-2006. Subsequent to the end of the second fiscal quarter, the company was finalizing an agreement with an industry participant for this project.

As previously reported, joint venture presentations have been made to a range of companies, including several of the major oil and gas companies as well as several large independents. All of these companies have expressed a keen interest in Calliope, and joint venture discussions are continuing with several of those companies, including evaluation of candidate wells.

In addition to joint ventures and the Calliope drilling project, the company has successfully expanded its Calliope operations into Texas and Louisiana. In southwest Texas, the company recently completed two prototype Calliope installations which once again broadened Calliope s down-hole application, successfully lifting several times more fluid volume than Calliope has previously lifted from the company s Oklahoma wells. Although this prototype Calliope configuration limits the amount of natural gas that can be produced during the start-up and dewatering phase, after initial dewatering and once liquid production stabilizes, the system can be optimized to allow greater natural gas flow. The company currently has three Calliope candidate wells that are awaiting Calliope installations, one in Louisiana and two in Oklahoma. If the company experiences no significant procurement delays, it expects that the installations will be complete in the company s third fiscal quarter. These efforts are being spearheaded on a full-time basis by a highly qualified petroleum engineer based in Houston.

Results of Operations

Six Months Ended April 30, 2006 Compared to Six Months Ended April 30, 2005

For the six months ended April 30, 2006, total revenues increased 51% to $8,286,000 compared to $5,485,000 last year. As the oil and gas price/volume table on page 13 shows, total gas price realizations, which reflect hedging transactions, increased 28% to $6.91 per Mcf and oil price realizations increased 36% to $59.37 per barrel. The net effect of these price changes was to increase oil and gas sales by $1,587,000. For the six months ended April 30, 2005, the company s gas equivalent production increased 13% resulting in an oil and gas sales increase of $867,000. Investment income and other increased $347,000 primarily due to the performance of the company s investments.

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For the six months ended April 30, 2006, total costs and expenses rose 45% to $3,969,000 compared to $2,731,000 for the comparable period in 2005. Oil and gas production expenses increased 54% due primarily to an increase in production taxes and lease operating expense. Production taxes increased during the current period primarily due to increased production revenue and the company s receipt of a production tax rebate during the 2005 period. The increase in lease operating expense is primarily due to an increase in the number of wells owned by the company and from additional workover expenses incurred during the 2006 period. Depreciation, depletion and amortization (DD&A) rose 56% primarily due to increased production and an increase in the amortizable cost base. General and administrative expenses increased 7% primarily due to costs associated with compliance with Sarbanes-Oxley regulations. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28.5% for the 2006 period and 28.0% for the 2005 period.

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

For the three months ended April 30, 2006, total revenues increased 29% to $3,921,000 compared to $3,038,000 during the same period last year. As the oil and gas price/volume table on page 13 shows, total gas price realizations, which reflect hedging transactions, increased 6% to $5.85 per Mcf and oil price realizations increased 39% to $61.63 per barrel. The net effect of these price changes was to increase oil and gas sales by $336,000. For the three months ended April 30, 2006, the company s gas equivalent production increased 13% resulting in an oil and gas sales increase of $383,000. Investment and other income increased $164,000 primarily due to the performance of the company s investments.

For the three months ended April 30, 2006, total costs and expenses rose 33% to $1,958,000 compared to $1,472,000 for the comparable period in 2005. Oil and gas production expenses increased 15% due primarily to an increase in production taxes and lease operating expense. DD&A rose 58% primarily due to increased production and an increase in the amortizable cost base. General and administrative expenses increased 25% primarily due to costs associated with compliance with Sarbanes-Oxley regulations. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 29.1% for the 2006 period and 28.0% for the 2005 period.

SIGNIFICANT ACCOUNTING POLICIES

The company believes the following accounting policies and estimates are critical in the preparation of its consolidated financial statements: the carrying value of its oil and natural gas properties, the accounting for oil and gas reserves, and the estimate of its asset retirement obligations.

OIL AND GAS PROPERTIES. The company uses the full cost method of accounting for costs related to its oil and natural gas properties. Capitalized costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. Depreciation, depletion and amortization is a significant component of oil and natural gas properties. A change in proved reserves without a corresponding change in capitalized costs will cause the depletion rate to increase or decrease.

Both the volume of proved reserves and any estimated future expenditures used for the depletion calculation are based on estimates such as those described under Oil and Gas Reserves below.

The capitalized costs in the full cost pool are subject to a quarterly ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10 percent plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower depreciation and depletion in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling.

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The company has made only one ceiling write-down in its 28-year history. That write down was made in 1986 after oil prices fell 51% and natural gas prices fell 45% between fiscal year end 1985 and 1986.

Changes in oil and natural gas prices have historically had the most significant impact on the company s ceiling test. In general, the ceiling is lower when prices are lower. Even though oil and natural gas prices can be highly volatile over weeks and even days, the ceiling calculation dictates that prices in effect as of the last day of the test period be used and held constant. The resulting valuation is a snapshot as of that day and, thus, is generally not indicative of a true fair value that would be placed on the company s reserves by the company or by an independent third party. Therefore, the future net revenues associated with the estimated proved reserves are not based on the company s assessment of future prices or costs, but rather are based on prices and costs in effect as of the end the test period.

OIL AND GAS RESERVES. The determination of depreciation and depletion expense as well as ceiling test write-downs related to the recorded value of the company s oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves. Oil and natural gas reserves include proved reserves that represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the company s control. Accordingly, reserve estimates are often different from the quantities of oil and natural gas ultimately recovered and the corresponding lifting costs associated with the recovery of these reserves.

At October 31, 2005, the date of the company s most recent reserve report, the company s reserves, and reserve values, were concentrated in 54 properties (Significant Properties). Some of the Significant Properties were individual wells and others were multi-well properties. The Significant Properties represented 28% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual wells on which the company s patented liquid lift system is installed comprise 22% of the Significant Properties and represented 32% of the discounted reserve value of such properties. Relatively new wells comprised 22% of the Significant Properties and represented 24% of the discounted value of such properties.

Estimates of reserve quantities and values for certain Significant Properties must be viewed as being subject to significant change as more data about the properties becomes available. Such properties include wells with limited production histories and properties with proved undeveloped or proved non-producing reserves. In addition, the company s patented liquid lift system is generally installed on mature wells. As such, they contain older down-hole equipment that is more subject to failure than new equipment. The failure of such equipment, particularly casing, can result in complete loss of a well. Historically, performance of the company s wells has not caused significant revisions in its proved reserves.

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The following table sets forth, as of October 31 of the indicated year, information regarding the company s proved reserves which is based on the assumptions set forth in Note (8) to the company s Consolidated Financial Statements on Form 10-K for the year ended October 31, 2005 where additional reserve information is provided. The average price used to calculate estimated future net revenues was $55.59, $50.43 and $28.64 per barrel of oil and $10.26, $5.84, and $3.99 per Mcf of gas as of October 31, 2005, 2004, and 2003, respectively. Amounts do not include estimates of future Federal and state income taxes.

Year	Oil (bbls)*	Gas (Mcf)*	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2005	386,000	15,516,000	$ 136,878,000	$ 81,209,000
2004	407,000	15,273,000	$ 77,612,000	$ 44,551,000
2003	385,000	13,786,000	$ 45,165,000	$ 28,024,000

* The percentage of total reserves classified as proved developed was approximately 89% in 2005, 93% in 2004 and 99% in 2003.

Estimated Future Net Revenues Discounted at 10% is not a GAAP measure of operating performance. Because the Company drills new wells on an ongoing basis, and plans to continue to do so in the future, it expects to continue to generate deferred income taxes which are not reasonable expected to be paid in the near term. This pre-tax, non-GAAP measure is used by the company in connection with estimating funds expected to be available in the future for drilling and other operating activities. The company believes that this performance measure may also be useful to investors for the same purpose. The difference between this measure and the Standardized Measure of Discounted Future Net Cash Flows From Reserves is that this measure excludes future income tax expense and the effect of the 10% discount factor on future income tax expense. In this Form 10-Q, the Company is providing the following information to enhance and supplement the disclosures contained in it Form 10-K for the year ended October 31, 2005. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows From Reserves as shown in Note 8 to the Company s Consolidated Financial Statements on Form 10-K for the year ended October 31, 2005.

	Year Ended October 31,		
	2005	2004	2003
Estimated future net revenues discounted at 10%	$ 81,209,000	$ 44,551,000	$ 28,024,000
Future income tax expense	(36,054,000)	(19,965,000)	(11,094,000)
Effect of the 10% discount factor on future income tax expense	14,332,000	8,273,000	4,211,000
Standardized measure of discounted future net cash flows from reserves	$ 59,487,000	$ 32,859,000	$ 21,141,000

Price changes will affect the economic lives of oil and gas properties and, therefore, price changes may cause reserve revisions. Price changes have not caused significant proved reserve revisions by the company except in 1986 when a 51% decline in oil prices and a 45% decline in natural gas prices resulted in an 8.7% reduction in estimated proved reserves. Based upon this historical experience, the company does not believe its reserve estimates are particularly sensitive to prices changes within historical ranges.

One measure of the life of the company s proved reserves can be calculated by dividing proved reserves at a fiscal year end by production for that fiscal year. This measure yields an average reserve life of nine years at October 31, 2005. Since this measure is an average, by definition, some of the company s properties will have a life shorter than the average and some will have a life longer than the average. The expected economic lives of the company s properties may vary widely depending on, among other things, the size and quality, natural gas and oil prices, possible curtailments in consumption by purchasers, and changes in governmental regulations or taxation. As a result, the company s actual future net cash flows from proved reserves could be materially different from its estimates.

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The company is not aware of any material adverse issues related to its reserves regarding regulatory approval, the availability of additional development capital, or the installation of additional infrastructure.

ASSET RETIREMENT OBLIGATIONS. SFAS No. 143, *Accounting for Asset Retirement Obligations* requires that the company estimate the future cost of asset retirement obligations, discount that cost to its present value, and record a corresponding asset and liability in its Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, market risk premiums, useful life, and cost of capital. The nature of these estimates requires the company to make judgments based on historical experience and future expectations. Revisions to the estimates may be required based on such things as changes to cost estimates or the timing of future cash outlays. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis.

REVENUE RECOGNITION. The company derives its revenue primarily from the sale of produced natural gas and crude oil. The company reports revenue gross for the amounts received before taking into account production taxes and transportation costs which are reported as oil and gas production expenses. Revenue is recorded in the month production is delivered to the purchaser at which time title changes hands. The company makes estimates of the amount of production delivered to purchasers and the prices it will receive. The company uses its knowledge of its properties; their historical performance; the anticipated effect of weather conditions during the month of production; NYMEX and local spot market prices; and other factors as the basis for these estimates. Variances between estimates and the actual amounts received are recorded when payment is received.

A majority of the company s sales are made under contractual arrangements with terms that are considered to be usual and customary in the oil and gas industry. The contracts are for periods of up to five years with prices determined based upon a percentage of a pre-determined and published monthly index price. The terms of these contracts have not had an effect on how the company recognizes its revenue.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The company manages exposure to commodity price fluctuations by periodically hedging a portion of expected production through the use of derivatives, typically collars and forward short positions in the NYMEX futures market. See Management s Discussion and Analysis of Financial Condition and Results of Operations Product Prices and Production for more information on the company s hedging activities. The company currently has no open hedge positions.

ITEM 4. CONTROLS AND PROCEDURES

The effectiveness of our or any system of disclosure controls and procedures is subject to certain limitations, including the exercise of judgment in designing, implementing and evaluating the controls and procedures, the assumptions used in identifying the likelihood of future events, and the inability to eliminate misconduct completely. As a result, there can be no assurance that our disclosure controls and procedures will detect all errors or fraud. By their nature, our or any system of disclosure controls and procedures can provide only reasonable assurance regarding management s control objectives.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act) as of April 30, 2006. On the basis of this review, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures are designed, and are effective, to give reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed in the reports filed or submitted

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under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, in a manner that allows timely decisions regarding required disclosure. There were no changes in the company s internal controls over financial reporting that occurred in the second fiscal quarter of 2006 that materially affected or were reasonably likely to materially affect, its internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors previously disclosed in the company s Annual Report on Form 10-K for the fiscal year ended October 31, 2005.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The company s annual meeting of stockholders was held on March 23, 2006, for the purpose of electing two Class II directors and ratifying the appointment of Hein & Associates LLP as the company s independent registered public accounting firm. Proxies for the meeting were solicited pursuant to Section 14(a) of the Securities Exchange Act of 1934 and there was no solicitation in opposition to management s solicitation. Each of management s nominees for Class II directors, as listed in the proxy statement, was elected with the number of votes set forth below.

Name	For	Withheld
James T. Huffman	6,234,662	223,741
Clarence H. Brown	6,421,251	37,152

Continuing Directors:

After the company s annual meeting on March 23, 2006, the following directors continued to serve their three-year terms as Class III directors, which terms will expire at the company s 2008 annual meeting:

William N. Beach
Richard B. Stevens

After the company s annual meeting on March 23, 2006, the following directors continued to serve their three-year terms as Class I directors, which terms will expire at the company s 2007 annual meeting:

Oakley Hall
William F. Skewes

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibits are as follow:

31.1	Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by Chief Executive Officer and Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act (18 U.S.C. Section 1350)

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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.

CREDO Petroleum Corporation
(Registrant)

By: /s/ James T. Huffman
James T. Huffman
President and Chief Executive Officer
(Principal Executive Officer)

By: /s/ David W. Vreeman
David W. Vreeman
Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)

Date: June 14, 2006

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Exhibit Index

Exhibit No.	Description
31.1	Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by Chief Executive Officer and Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act (18 U.S.C. Section 1350)