CREDO Petroleum Corporation

2007 Annual Report

Corporate Profile

CREDO Petroleum Corporation is an independent oil and gas exploration and development company. CREDO focuses on two core projects—natural gas drilling and application of its patented Calliope Gas Recovery System. The company operates primarily in the Mid-Continent Region of the United States, with minor operations in the Rocky Mountain Region. CREDO owns working and royalty interests in approximately 1,445 wells and acts as the operator of approximately 115 wells.

Financial Data	2007	2006	Change
Income Per Share — Diluted	**$ .65**	$ .62	5%
Revenues	**$ 16,993,000**	$ 16,491,000	3%
Working Capital	**$ 12,511,000**	$ 10,073,000	24%
Debt	**$ 162,000**	$ 233,000	-30%
Shareholders' Equity	**$ 41,140,000**	$ 34,767,000	18%
Total Assets	**$ 55,349,000**	$ 47,459,000	17%
Common Shares Outstanding	**9,510,000**	9,510,000	—

Operations Data	2007	2006	Change
Reserves:			
Volume (Mcfge)	**20,517,000**	18,537,000	11%
Future Net Revenues	**$ 101,501,000**	$ 84,861,000	20%
Future Net Revenues Discounted at 10%	**$ 62,071,000**	$ 52,328,000	19%
Production (Mcfge)	**2,234,000**	2,422,000	-8%
Acreage:			
Gross Acres	**366,000**	348,000	5%
Net Acres	**65,000**	58,000	12%

Forward Looking Statements

Forward-looking statements are made in this Annual Report to give the reader an indication of our business prospects, plans and objectives, and include statements relating to, among other things, our business strategy, success of new projects, expansion and growth of production and reserves, anticipated number of wells to be drilled, commencement date of drilling, drilling costs, growth, benefits and success of Calliope and reserve targets. Although we believe these statements are reasonable at this time, actual results, performance or achievements could differ materially from those stated. Readers should refer to the risks involved in making these statements, which are given on page 2 of our Form 10-K, contained herein.

Fellow Shareholders:

Once again I am pleased to report that we had an excellent year. New records were established this year in almost all operating and financial categories, highlighted by an 18 percent return on equity without using leverage. This is the fifth consecutive year that Credo has generated record financial results, and the fourteenth consecutive year of record reserves.

I am also pleased to report that we have made good progress on the Calliope joint venture front, and that we have some exciting drilling opportunities on the immediate horizon. If these projects realize their potential, the result will generate significant value for our shareholders.

Our straightforward goals are grounded on properly managing our costs and risks:

- Earn a profit that will provide an excellent return on our shareholders' investment
- Increase production volumes
- Replace produced reserves and increase the reserve base

In addition to making a record profit, we replaced 189 percent of this year's oil and natural gas production. Our 2007 capital investment of $8,834,000 generated proved reserves totaling 220,000 barrels of oil and 2.9 billion cubic feet of gas. Our reserve replacement cost was a low $1.68 per thousand cubic of gas equivalent, excluding the cost of undeveloped properties. Our 2007 finding cost is lower than last year which is a significant achievement in view of the rapidly rising cost of field services.

We did not achieve our production goal because of the timing of two exceptionally high rate discoveries last year. Flush production from those discoveries caused prior year production to increase 18%, which was more than we could overcome this year. The table below shows our five year compound average growth rate for production and certain other critical financial and operating categories.

	Five Year CAGR
• Production increase	8%
• Reserve increase	12%
• Revenue increase	28%
• Net income increase	39%

Credo's shareholder returns are among the top of U.S. public companies with almost a 300 percent five year gain and an 800 percent ten year gain. Despite this year's record performance and our consistent long-term growth, our stock price ended the year significantly lower than last year's close. As Credo's largest shareholder, that is particularly disappointing to me because I do not believe that the stock price properly reflects Credo's current underlying value. We have seen cycles like this before, and I am certain that Credo's stock will adjust accordingly as our staff continues to manage a strong asset base with our successful and time tested business strategy.

Once again in 2007, we did a substantial amount of natural gas price hedging. Because gas prices have an enormous impact on our financial performance, we have a long-standing policy of actively managing prices through hedging. This plays an important role in maintaining the consistent long-term performance that creates confidence and credibility with all of our constituencies.

Business Strategy. We have an excellent portfolio of assets, and our people are executing a consistent and well designed strategy that has produced outstanding long term results. Our business focuses on two core strategies: application of our patented Calliope technology and conventional drilling. These two strategies are very synergistic and both have contributed significantly to the consistent achievement of our goals. We have also received the initial patent on another new fluid lift technology that has very broad application for shallow wells. We expect to begin field testing the new system this summer.

Calliope Gas Recovery System. I am pleased to report that we have recently completed two new Calliope joint venture agreements. One agreement provides for a substantial license fee based on meeting a specified future performance threshold. The other provides for Credo to share in up to 50 percent of the Calliope production from what I anticipate will be a significant number of wells.

The recent joint ventures are a direct result of the new approach we implemented this year in response to obstacles that we have encountered. Despite initial enthusiasm for Calliope, we often see project proposals get delayed or suspended in the numerous layers of review and approval that are required by large companies.

To address that problem, we developed a new and interactive way to present Calliope that can be easily tailored to the needs of the audience. Our new presentation allows us to efficiently inform people of all disciplines and at all levels within large organizations about how Calliope works and its impressive track record.

We compiled empirical data for the new presentation that shows the advantages of using Calliope early in a well's life as a single step solution to liquid loading problems. We have also developed data that clearly demonstrates how Calliope has created a significant production advantage over other wells in the same reservoir. I recommend our December 2, 2007 press release for your review and consideration because it contains very detailed information about Calliope's track record.

The data shows that Calliope has created almost $100,000,000 of gross value at today's natural gas prices from a group of 14 wells that were previously dead or uneconomic. These are the non-experimental, "go forward" applications that represent a wide variety of Calliope options which can be readily applied to other wells.

With Calliope installed, the 14 wells have already produced an incremental 3.4 billion cubic feet of gas, worth about $23,000,000 at today's gas prices. The wells are still highly profitable, producing about 60.0 million cubic feet of gas per month worth over $5,000,000 per year. Total ultimate Calliope reserves of about 14.0 billion cubic feet of gas were estimated for these wells.

Calliope added those reserves at a finding cost of only $0.41 per thousand cubit feet. That is an extremely low finding cost, particularly when compared to the industry-wide finding cost last year of over $3.00. The "all in" Calliope cost, which includes the costs to produce and sell the gas, is only $1.02 per thousand cubic feet.

This economic result on "down and out" wells is nothing short of remarkable, and the performance of the wells is a testament to how Calliope can add new domestic reserves in the face of rising demand for foreign energy.

One of the 14 wells, the J.C. Carroll, had been dead for five years when Calliope was installed. Previous operators had exhausted the other fluid lift options before Credo purchased the well. We installed Calliope and the well immediately came back to life producing at the rate of 20 million cubic feet of gas per month. With Calliope, the previously dead Carroll well has already produced over 1.0 billion cubic feet of Calliope gas, and it is expected to ultimately produce between 1.5 and 1.7 billion cubic feet of Calliope gas reserves.

We have proven beyond any doubt that Calliope will perform as advertised. We are now working at various levels with interested companies, and I am optimistic that additional joint ventures will result from the discussions. I am also confident that, as we bring Calliope into large companies, it will generate a lot of enthusiasm as word spreads about Calliope's performance and outstanding economics.

Drilling and Exploration. We are pleased with each of our three primary drilling projects. The deep Wilcox drilling about to kick off in South Texas, in particular, has enormous potential to increase our production and reserves.

Oklahoma drilling has historically been the primary driver for Credo's production growth. We own approximately 75,000 gross acres in Oklahoma and have interests in almost 200 wells. We have drilled over 80 wells in the past five years. Nine separate prospects are currently being developed and we are planning wildcat drilling on several new prospects. We expect our drilling activity to continue to be concentrated in Oklahoma during 2008. In particular, we are about to drill for multiple carbonate zones in Major County that we characterize as a "resource play" due to the number of stacked zones and their production profiles. If the drilling works as expected, we could have 12 to 15 possible locations on current Credo acreage where we own interests ranging from 50 to 70 percent.

We are also very pleased with recent successes on our Central Kansas drilling project where four 100 barrel per day wells have been drilled. This is Credo's primary oil play, and we have built our position in the play to about 50,000 gross acres consisting of four separate projects with interests ranging form 12.5 percent to 70 percent. Our drilling results have improved dramatically in recent months as we continue to find the keys to successful seismic and geological interpretations. We hope to substantially build our interest in the play during 2008 to further diversify our drilling program.

In South Texas, Credo owns up to 11 percent in the high risk but high potential Gemini Prospect where gross reserves in the hundreds of billions of cubic feet of gas are well within reason. In return for generating the prospect, Credo will receive cash consideration and our interest will be "carried" through the pipeline connection on the first two wells. This eliminates our exploratory drilling risk while maintaining our lower risk development rights.

A wildcat well will be drilled to test the Wilcox sands at 17,500 feet as soon as the operator secures a top quality rig. Gemini Prospect is located about seven miles southeast of the N.E. Thompsonville Field which has produced over 820 billion cubic feet of gas from the Wilcox sands. Seismic over both the Gemini Prospect and the N.E. Thompsonville Field indicates that the Gemini Prospect has a structural trap similar in character to N. E. Thompsonville Field. The presence of the Wilcox sands on the Gemini Prospect is indicated by 3-D seismic correlation to an old Amoco well located about four miles to the south which found 300 feet of highly porous, but wet, Wilcox sands. Our modern seismic suggests that a well on the Gemini Prospect should penetrate a large structural closure (up to 1,200 acres) located in a separate fault block about 1,300 feet high to the Amoco well. That provides the opportunity for a significant gas accumulation up-dip from the dry hole. Two sister prospects located just north of Gemini will be tested for the deep Wilcox formation if our first well is a discovery. The size of Gemini Prospect, coupled with the substantial drilling opportunities to the north, would have an enormous positive impact on Credo's production and reserve growth if the play is successful.

The Future. By most measures, our company has doubled and tripled in size during the past five years. We have excellent people who are dedicated to Credo's continued success, and they manage a strong asset base with a business strategy that has proven successful for Credo.

In a short time, we have completed four Calliope joint ventures, and we are currently working on joint ventures with several more companies that are intrigued by the technology and its impressive track record. As we have grown, we have maintained our drilling momentum in Oklahoma while diversifying into major new projects in South Texas and Central Kansas. The latter projects are just now maturing to the point where they can make a substantial contribution to Credo's future growth.

Your management and Board members are highly engaged in the success of Credo because we have a 20% stake in the outcome. We will continue to pursue growth opportunities with the strategic discipline that has produced our long record of outstanding operating and financial performance. As always, we appreciate your support, and we are mindful of our duty to uphold the trust you have placed in us through your ownership of Credo shares.

James T. Huffman
President and Chief Executive Officer
January 28, 2008

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

FORM 10-K

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

For The Fiscal Year Ended October 31, 2007

or

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

For the transition period from __________ to __________

Commission File Number 0-8877

SEC
Mail Processing
Section

MAR 04 2008

Washington, DC
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CREDO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Colorado	84-0772991
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1801 Broadway, Suite 900, Denver, Colorado 80202-3837
(Address of principal executive offices and zip code)

Registrant's telephone number, including area code: (303) 297-2200

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, $.10 Par Value
(Title of class and shares outstanding)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act: ____ Yes X No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act: ____ Yes X No

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. X Yes ____ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this form 10-K or any amendment to this Form 10-K. X

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 ____ Accelerated filer X Non-accelerated filer ____

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of April 30, 2007, the end of the registrant's most recently completed second quarter was $110,276,000.

As of January 8, 2008, the registrant had 9,295,000 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Pursuant to instruction G (3) to Form 10-K, Items 10, 11, 12, 13 and 14 are omitted because the company will file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such items will be included in the Proxy Statement to be so filed for the company's annual meeting of shareholders to be held on or about March 20, 2008 and is hereby incorporated by reference.

NON-GAAP FINANCIAL MEASURES

In this Annual Report on Form 10-K, the company uses the term "EBITDA (Earning Before Interest, Taxes, Depreciation and Amortization)" which is considered a non-GAAP financial measure as defined in SEC Regulation S-K Item 10 and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations for a definition of this measure as used in this Annual Report on Form 10-K.

Estimated Future Net Revenues Discounted at 10% is not a GAAP measure of operating performance. 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. See Item 2 PROPERTIES, Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues for a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note 9 to the company's Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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 Annual Report on Form 10-K, 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 include, among other things, statements relating to:

- the company's future financial position, including working capital and anticipated cash flow;
- amounts and nature of future capital expenditures;
- projections of operating costs and other expenses;
- wells to be drilled or reworked including new drilling expectations;
- expectations regarding oil and natural gas prices and demand;
- existing fields, wells and prospects;
- diversification of exploration, capital exposure, risk and reserve potential of drilling activities;
- estimates of proved oil and natural gas reserves;
- expectations and projections regarding joint ventures;
- reserve potential;
- development and drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- the company's business strategy;
- production and production potential of oil and natural gas;
- matters related to the Calliope Gas Recovery System, including projections for future use of Calliope and the success of Calliope;
- effects of federal, state and local regulation;
- adequacy of insurance coverage;
- employee relations;
- effectiveness of the company's hedging transactions;
- investment strategy and risk; and
- expansion and growth of the company's business and operations.

Although the company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. Disclosure of important factors that could cause actual results to differ materially from the company's expectations, or cautionary statements, are included under "Risk Factors" and elsewhere in this Annual Report on Form 10-K, including, without limitation, in conjunction with the forward-looking statements. The following factors, among others that could cause actual results to differ materially from the company's expectations, include:

- unexpected changes in business or economic conditions;
- significant changes in natural gas and oil prices;
- timing and amount of production;
- unanticipated down-hole mechanical problems in wells or problems related to producing reservoirs or infrastructure;
- changes in overhead costs;
- material events resulting in changes in estimates; and
- competitive factors.

All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to the company, or persons acting on the company's behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, the company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

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PART I

ITEM 1. BUSINESS

General

CREDO Petroleum Corporation ("CREDO") was incorporated in Colorado in 1978. CREDO and its wholly owned subsidiaries, SECO Energy Corporation and United Oil Corporation ("SECO", "United" and collectively "the company"), are Denver, Colorado based independent oil and gas companies which engage primarily in oil and gas exploration, development and production activities in the Mid-Continent region of the United States. The company has operating activities in ten states and has twelve full-time employees. CREDO is an active operator in Kansas, Wyoming, Colorado, Louisiana and Texas. United is an active operator doing business primarily in Oklahoma, and SECO primarily owns royalty interests in the Rocky Mountain region. References to years as used in this report indicate fiscal years ended October 31.

The company effected a 20% stock dividend in fiscal 2003, and a three-for-two stock split in each of fiscal 2005 and 2004. All share and per share amounts discussed and disclosed in this Annual Report on Form 10-K reflect the effect of the dividend and stock splits.

Business Activities

During 2007, the company continued implementation of new drilling projects in central Kansas and South Texas, which projects are designed to sustain the company's growth rate by expanding and diversifying its business, both technically and geographically. These projects will also diversify the capital exposure, risk and reserve potential of the company's drilling activities. This includes approximately equal commitments to conventional drilling and to the company's patented Calliope Gas Recovery System ("Calliope") operations.

The company's goal is to create steady growth by adding production and long-lived reserves at reasonable costs and risks. The strategy to achieve this goal involves conventional drilling and increasing the number of Calliope installations. Third party industry participants are involved in most of the company's operating activities.

Historically, the company's primary drilling focus has been in the Anadarko Basin of Oklahoma where the company owns interests in approximately 70,000 gross acres. The company will continue generating prospects and drilling on this acreage concentrating on medium depth properties generally ranging from 7,000 to 11,000 feet. Refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations-Oil and Gas Activities-Drilling Activities-Northern Anadarko Basin" for additional information.

In recent years, the company has significantly expanded both the volume and breadth of its exploration program with new projects in South Texas and north-central Kansas. Compared to drilling in Oklahoma, the South Texas project involves higher costs and greater risks but significantly higher per well reserve potential. The South Texas project is 3-D seismic driven with well depths ranging from 10,000 to 17,000 feet. The north-central Kansas project is geared to oil exploration and has excellent potential to add significant reserves at moderate costs and risks. This project is also 3-D seismic driven with well depths of approximately 4,000 feet. Exploration teams for both projects specialize in their respective geographic areas and have been highly successful finding new reserves using 3-D seismic. The company believes that both projects have the potential to generate significant future production and reserve growth. Refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Oil and Gas Activities—Drilling Activities-Drilling Program Expansion and Diversification, South Texas, and North-Central Kansas" for additional information.

The company has participated in developing, testing, refining, and patenting Calliope. Calliope efficiently lifts fluids from wellbores using pressure differentials, thus allowing gas previously trapped by fluid build-up in the wellbore to flow to the surface. Calliope is distinguished from all other fluid lift technologies because it does not rely on bottom-hole pressure and has only one down-hole moving part. Calliope is primarily applicable to mature natural gas wells in low pressure, natural gas expansion reservoirs at depths below 8,000 feet. The company has a 10 year unrestricted exclusive license for the Calliope technology that expires in 2010, but that can be extended, at the company's option, to cover the term of the latest patent. External sources of capital have not been required for the development, refinement or installation of Calliope. At October 31, 2007, Calliope has been installed on 25 wells ranging in depth from 6,500 feet to 18,400 feet. The company has proven Calliope's economic viability and flexibility over a wide range of applications.

The company currently has Calliope installed on wells located in Oklahoma, Texas and Louisiana which include both sandstones and limestones in Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Red Fork and Springer reservoirs. Joint venture discussions were accelerated in fiscal year 2007 with two new agreements reached and others under negotiation at October 31, 2007. Refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations-Oil and Gas Activities-Calliope Gas Recovery Technology" for additional information.

The company acts as "operator" of approximately 115 wells pursuant to standard industry operating agreements. The company owns working interests in 282 producing wells and overriding royalty interests in 1,163 wells.

Markets and Customers

Marketing of the company's oil and gas production is influenced by many factors which are beyond the company's control, and the exact effect of which cannot be accurately predicted. These factors include changes in supply and demand, market prices, regulation, and actions of major foreign producers. Oil price fluctuations can be extremely volatile as was demonstrated when, during 2003, the posted price for West Texas intermediate fell below $25.00 per barrel and then rose to over $90.00 per barrel during 2007.

Natural gas price decontrol, the advent of an active spot market for natural gas, changes in supply and demand for natural gas, and weather patterns cause natural gas prices to be subject to significant fluctuations. The company presently sells virtually all of its natural gas under one to five year contracts with major pipeline companies. The sales price is typically based on monthly index prices for the applicable pipeline. Title to the natural gas normally passes to the pipeline at meters located near the wells. The index prices are reduced by certain pipeline charges.

Most of the company's natural gas production is located in northwestern Oklahoma. There has been significant consolidation among natural gas pipelines in this area, thereby reducing the number of available purchasers. In many instances, there may be only one viable pipeline option, which enables the pipeline to charge higher rates. A new pipeline is scheduled to be completed in early 2008 that will transport gas from the Rocky Mountain region to northeast Missouri. The pipeline will connect with other pipelines that transport natural gas to the eastern United States. Depending on supply and demand factors, gas delivered from the Rocky Mountain region may compete with the company's Oklahoma gas resulting in the possibility of downward pressure on gas prices received by the company in Oklahoma and may cause ineffectiveness in the company's cash flow hedges.

Over the past few years there has been increasing concern that a supply/demand imbalance has developed in domestic natural gas based on increasing demand and lower deliverability. This, together with rising oil prices, political unrest and uncertainty in certain major producing regions, supply vulnerability to natural disasters, such as hurricanes, and active speculation in the natural gas futures market has caused natural gas prices to become increasingly volatile. The company expects natural gas prices to remain strong but cannot reasonably predict the extent or timing of natural gas price fluctuations.

As discussed elsewhere in this Annual Report on Form 10-K, the company periodically hedges the price of a portion of its estimated natural gas production in the form of forward short positions and collars on both the NYMEX futures market and regional markets.

Oil production is sold to crude oil purchasing companies at competitive spot field prices. Crude oil and condensate production are readily marketable, and the company is generally not dependent on a single purchaser. Crude oil prices are subject to world-wide supply and demand, and are primarily dependent upon available supplies which can vary significantly depending on production and pricing policies of OPEC and other major producing countries and on significant events in major producing regions. Political unrest and market uncertainty in the Middle East, Africa, South America and former Soviet Union, OPEC's renewed cooperation in managing the price of its produced oil, and increased demand from countries with developing economies, such as China and India, have resulted in higher world-wide oil prices during the past several years.

Information concerning the company's major customers is included in Note (9) to the Consolidated Financial Statements.

Competition and Regulation

The oil and gas industry is highly competitive. As a small independent, the company must compete against companies with substantially larger financial, human and other resources in all aspects of its business.

Oil and gas drilling and production operations are regulated by various federal, state and local agencies. These agencies issue binding rules and regulations which carry penalties, often substantial, for failure to comply. The company anticipates its aggregate burden of federal, state and local regulation will continue to increase particularly in the area of rapidly changing environmental laws and regulations. The company also believes that its present operations substantially comply with applicable regulations. To date, such regulations have not had a material effect on the company's operations, or the costs thereof. There are no known environmental or other regulatory matters related to the company's operations which are reasonably expected to result in material liability to the company. The company believes that capital expenditures related to environmental control facilities or other regulatory matters will not be material in 2008. The company cannot predict what subsequent legislation or regulations may be enacted or what effect they might have on the company's business.

ITEM 1A. RISK FACTORS

In evaluating the company, careful consideration should be given to the following risk factors, in addition to the other information included or incorporated by reference in this Annual Report on Form 10-K. Each of these risk factors could adversely affect the company's business, operating results and financial condition, as well as adversely affect the value of an investment in the company's common stock.

Volatility of oil and natural gas prices could adversely affect the company's profitability and financial condition.

The company's performance in terms of revenues, operating results, profitability, future rate of growth and the carrying value of its oil and natural gas properties is significantly impacted by prevailing market prices for oil and natural gas. Any substantial or extended decline in the price of oil or natural gas could have a material adverse effect on the company. It could reduce the company's operating cash flow as well as the value and, to a lesser degree, the quantity of its oil and natural gas reserves. See the table of oil and gas sales volumes and prices on page 13 for further information.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile. Relatively minor changes in supply or demand can have a significant effect on oil and natural gas prices. Some of the factors affecting oil and natural gas prices which are beyond the company's control include:

- worldwide and domestic supplies of oil and natural gas;
- worldwide and domestic demand for oil and natural gas;
- the ability of the members of OPEC to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil or natural gas producing regions;
- worldwide and domestic economic conditions;
- the availability of transportation facilities;
- weather patterns; and
- actions of governmental authorities.

Competition for opportunities to replace and increase production and reserves is intense and could adversely affect the company.

Properties produce at a declining rate over time. In order to maintain current production rates the company must add new oil and natural gas reserves to replace those being depleted by production. Competition within the oil and natural gas industry is intense and many of the company's competitors have financial and other resources substantially greater than those available to the company. This could place the company at a disadvantage with respect to accessing opportunities to maintain, or increase, its oil and natural gas reserve base.

In the event that the company does not have adequate cash flow to fund operations, it may be required to use debt or equity financing.

The company makes, and will continue to make, significant expenditures to find, acquire, develop and produce oil and natural gas reserves. If oil and natural gas prices decrease, or if operating difficulties are encountered that result in cash flow from operations being less than expected, the company may have to reduce capital expenditures unless additional funds are raised through debt or equity financing. Debt or equity financing or cash generated by operations may not be available to the company in sufficient amounts or on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the company's success in locating and producing new reserves;
- the level of production from existing wells; and
- prices of oil and natural gas;

Issuing equity securities to satisfy the company's financing requirements could cause substantial dilution to existing stockholders. Debt financing could make the company more vulnerable to competitive pressures and economic downturns.

Reserve quantities and values are subject to many variables and estimates and actual results may vary.

This Annual Report on Form 10-K contains estimates of the company's proved oil and natural gas reserves and the estimated future net revenues from those reserves. Any significant negative variance in these estimates could have a material adverse effect on the company's future performance.

Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data.

Reserve estimates are dependent on many variables, and therefore, as more information becomes available, it is reasonable to expect that there will be changes to the estimates. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by the company. In addition, estimates of proved reserves will be adjusted in the future to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond the company's control.

As of October 31, 2007, approximately 24% of the company's estimated proved reserves are classified as proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is generally based on volumetric calculations rather than the performance data used to estimate reserves for producing properties. Recovery of proved undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Revenues from proved developed non-producing and proved undeveloped reserves will not be realized until some time in the future. The reserve estimate includes an estimate of the capital expenditures required to develop these reserves as well as the timing of such expenditures. Although the company has prepared estimates of its proved undeveloped reserves and the associated development costs in accordance with industry standards, they are based on estimates, and actual results may vary.

You should not interpret the present value of estimated reserves, or PV-10, as the current market value of reserves attributable to the company's properties. The 10% discount factor, which we are required to use to calculate PV-10 for reporting purposes, is not necessarily the most appropriate discount factor given actual interest rates and risks to which the company's business or the oil and natural gas industry in general are subject. The company has based the PV-10 on prices and costs as of the date of the reserve estimate, in accordance with applicable regulations. Actual future prices and costs may be materially higher or lower. In addition to the price volatility factors discussed above, factors that will affect actual future net cash flows, include:

- the amount and timing of actual production;
- curtailments or increases in consumption by oil and natural gas purchasers; and
- changes in governmental regulations or taxation.

As a result, the company's actual future net cash flows could be materially different from the estimates included in this Annual Report on Form 10-K.

The company's reserve quantities and values are concentrated in a relative few properties and fields.

The company's reserves, and reserve values, are concentrated in 61 properties which represent 26% of the company's total properties but a disproportionate 77% of the discounted value (at 10%) of the company's reserves. Individual wells on which Calliope is installed comprise 20% of these significant properties and 22% of the discounted reserve value of such properties. New wells comprise 16% of these significant properties and 15% of the discounted reserve value of such properties.

Estimates of reserve quantities and values for these 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, Calliope 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.

Competition for materials and services is intense and could adversely affect the company.

Major oil companies, independent producers, and institutional and individual investors are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to develop and operate properties. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of the company's competitors have financial and technological resources which exceed those available to the company.

The company is currently experiencing delays in securing drilling rigs and 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.

The company's hedging arrangements involve credit risk and may limit future revenues from price increases.

To manage the company's exposure to price risks associated with the sale of natural gas, the company periodically enters into hedging transactions for a portion of its estimated natural gas production. These transactions may limit the company's potential gains if natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose the company to the risk of financial loss in certain circumstances, including instances in which:

- the company's production is less than the amount hedged;
- the contractual counterparties fail to perform under the contracts; or
- a sudden, unexpected event, materially impacts natural gas prices.

The terms of the company's hedging agreements may also require that it furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by the company to the counterparties, which would encumber the company's liquidity and capital resources.

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective.

Hedging gains and losses from effective cash flow hedges are recognized as adjustments to gas sales as the hedged product is produced. If price movements in cash flow hedges compared to the price received for the company's production cause the hedges to be ineffective then the related hedging gains and losses during the period of ineffectiveness will be immediately reported as gas sales. Ineffective cash flow hedges have not been material for the three years ended October 31, 2007.

A new pipeline is scheduled to be completed in early 2008 that will transport gas from the Rocky Mountain region to northeast Missouri. The pipeline will connect with other pipelines that transport natural gas to the eastern United States. Depending on supply and demand factors, gas delivered from the Rocky Mountain region may compete with the company's Oklahoma gas resulting in the possibility of downward pressure on gas prices received by the company in Oklahoma and may cause ineffectiveness in the company's cash flow hedges.

The marketability of the company's natural gas production is dependent upon infrastructure, such as gathering systems, pipelines and processing facilities, that the company does not own or control.

The marketability of the company's natural gas production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities necessary to move the company's natural gas production to market. The company does not own this infrastructure and is dependent on other companies to provide it.

Oil and natural gas operations are inherently risky.

The oil and natural gas business involves a variety of risks, including the risks of operating hazards such as fires, explosions, cratering, blow-outs, and encountering formations with abnormal pressures. The occurrence of any of these risks could result in losses. The company maintains insurance against some, but not all, of these risks. Management believes that the level of insurance against these risks is reasonable and is consistent with general industry practices. The occurrence of a significant event that is not fully insured could have a material adverse effect on the company's financial position and results of operations.

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.

The company has recently expanded the volume and breadth of its exploration program with new drilling projects in South Texas. These projects diversify the company's exploration geographically, scientifically, and in terms of capital, risk and reserve potential. Compared to the company's Oklahoma drilling, the South Texas project involves higher costs and greater risks but offers significantly higher per well production and reserve potential.

The company's operations are subject to a variety of regulatory constraints.

The production and sale of oil and natural gas are subject to a variety of federal, state and local government regulations. These include:

- the prevention of waste;
- the discharge of materials into the environment;
- the conservation of oil and natural gas;
- pollution;
- permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells; and
- the unitization and pooling of properties.

Because current regulations covering the company's operations are subject to change at any time, and despite its belief that it is in substantial compliance with applicable environmental and other government laws and regulations, the company could incur significant costs for future compliance.

Increases in taxes on energy sources may adversely affect the company's operations.

Federal, state and local governments which have jurisdiction in areas where the company operates impose taxes on the oil and natural gas products sold. Historically, there has been on-going consideration by federal, state and local officials concerning a variety of energy tax proposals. Such matters are beyond the company's ability to accurately predict or control.

The company is highly dependent on the services of one of its officers.

The company is highly dependent on the services of James T. Huffman, its President and Chief Executive Officer. The loss of Mr. Huffman could have a material adverse effect on the company.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The company does not have any unresolved comments from the Commission.

ITEM 2. PROPERTIES

General

The company's drilling activities are primarily located along the Northern Anadarko Basin of Oklahoma including the Oklahoma Panhandle where the company owns interests in approximately 70,000 gross developed and undeveloped acres. Specifically, drilling expenditures have been focused on prospects located in Harper, Ellis and Beaver Counties, Oklahoma. Wells target the Morrow and Chester formations between 7,000 and 11,000 feet. Since 2002, the company has participated in drilling approximately 89 wells on such prospects with interests ranging up to 83%. Of those wells, 64 were completed as producers and 25 were dry holes. Several of the wells are exceptional for the area, and 22 of the wells are included in the company's Significant Properties (see definition below). The company has recently expanded its drilling activities into South Texas and Kansas.

The company owns the exclusive right to the Calliope Gas Recovery System. The company has proven that Calliope will add 0.5 to 2.0 Bcf of proved gas reserves to many dead and uneconomic wells. The company believes there are presently many (more than 1,000) wells that meet its general criteria for Calliope candidate wells and thousands more that will meet its general Calliope criteria in the future.

Calliope operations were historically focused in Oklahoma where the company has a significant field operations infrastructure. Most Calliope wells are located in the Northern Anadarko Basin of Oklahoma. To date, Calliope has been installed on 25 wells located in Oklahoma, Texas and Louisiana. The Calliope wells include both sandstone and carbonate reservoirs including the Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Redfork and Springer formations. The Calliope wells range in depth from 6,400 to 18,400 feet. At the time Calliope was installed, 14 of the wells were dead, nine were uneconomic and two were marginal. There are 14 non-experimental Calliope wells. As a group, those wells were producing a total of 88 thousand cubic feet of gas per day at the time Calliope was installed. Since Calliope was installed, those wells have produced 3.4 billion cubic feet of gas and they now have estimated ultimate (8/8ths) Calliope reserves totaling 13.6 billion cubic feet of gas. Twelve of the Calliope wells are included in the company's Significant Properties.

For additional information regarding current year activities, including oil and gas production, refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues

The company's reserves, and reserve values, are concentrated in 61 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At year-end, Significant Properties represent 26% of the company's total properties but a disproportionate 77% of the discounted value (at 10%) of the company's reserves. Individual Calliope wells comprise 20% of the Significant Properties and represent 22% of the discounted reserve value of such properties. New wells comprise 16% of the Significant Properties and represent 15% 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 (including post Calliope installation wells) and properties with proved undeveloped or proved non-producing reserves. In addition, Calliope wells are generally 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.

McCartney Engineering, Inc., an independent petroleum engineering firm, estimated proved reserves for the company's properties which represented 64% in 2007, 63% in 2006 and 63% in 2005 of the total estimated future value of estimated reserves. Remaining reserves were estimated by the company in all years. At October 31, 2007, natural gas represented 83% and crude oil represented 17% of total reserves denominated in equivalent Mcf's using a six Mcf of gas to one barrel of oil conversion ratio.

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 (9) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $5.89, $6.32, and $10.26 per Mcf of gas and $86.61, $53.69, and $55.59 per barrel of oil as of October 31, 2007, 2006, and 2005, respectively. Amounts do not include estimates of future Federal and state income taxes.

Year	Gas (Mcf) *	Oil (bbls)*	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2007	**16,973,000**	**591,000**	**$ 101,501,000**	**$ 62,071,000**
2006	16,005,000	422,000	$ 84,861,000	$ 52,328,000
2005	15,516,000	386,000	$ 136,878,000	$ 81,209,000

* The percentage of total reserves classified as proved developed was approximately 76% in 2007, 87% in 2006, and 89% in 2005.

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 reasonably 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. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note 9 to the company's Consolidated Financial Statements.

	Year Ended October 31,		
	2007	2006	2005
Estimated future net revenues discounted at 10%......................	$ 62,071,000*	$ 52,328,000*	$ 81,209,000*
Future income tax expense	(24,967,000)	(20,747,000)	(36,054,000)
Effect of the 10% discount factor on future income tax expense	9,697,000	8,170,000	14,332,000
Standardized measure of discounted future net cash flows..................	$ 46,801,000	$ 39,751,000	$ 59,487,000

* The average price used to calculate estimated future net revenues was $5.89, $6.32, and $10.26 per Mcf of gas and $86.61, $53.69, and $55.59 per barrel of oil as of October 31, 2007, 2006, and 2005, respectively.

Production, Average Sales Prices and Average Production Costs

The company's net production quantities and average price realizations per unit for the indicated years are set forth below. Price realizations are net of any hedging gains or losses.

Product	2007 Volume	2007 Price	2006 Volume	2006 Price	2005 Volume	2005 Price
Gas (Mcf)	**1,926,000**	**$ 6.78**[1]	2,176,000	$ 6.11[2]	1,830,000	$ 6.16[3]
Oil (bbls)	**51,000**	**$ 60.95**	41,000	$ 61.14	37,000	$ 50.90

(1) Includes $0.99 Mcf hedging gain.
(2) Includes $0.12 Mcf hedging loss.
(3) Includes $0.39 Mcf hedging loss.

Average production costs, including production taxes, per equivalent Mcf of production (using a six Mcf of gas to one barrel of oil conversion ratio) were $1.51, $1.40, and $1.35 per Mcfe in 2007, 2006, and 2005, respectively.

Productive Wells and Developed Acreage

Developed acreage at October 31, 2007 totaled 27,000 net and 80,000 gross acres. At October 31, 2007, the company owned working interests in 82.13 net (282 gross) wells consisting of 65.52 net (236 gross) natural gas wells and 16.61 net (46 gross) oil wells. In addition, the company owned royalty and production payment interests in approximately 1,163 wells, primarily coal bed methane, located in Wyoming. In 2007, the company sold 0.28 net (one gross) well and abandoned 0.37 net (one gross) well. In the same period, the company drilled and acquired interests in 5.54 net (17 gross) productive wells in which it did not previously own an interest.

Undeveloped Acreage

The following table sets forth the number of undeveloped acres leased by the company (primarily located in the Mid-Continent and Rocky Mountain Regions) which will expire during the next five years (and thereafter) unless production is established in the interim. Undeveloped acres "held-by-production" represent the undeveloped portions of producing leases which will not expire until commercial production ceases.

Expiration Year Ending October 31,	Royalty Interest Acreage Gross	Royalty Interest Acreage Net	Working Interest Acreage Gross	Working Interest Acreage Net
2008	-	-	32,900	9,300
2009	-	-	8,200	4,200
2010	3,300	100	22,300	10,400
2011	-	-	100	-
2012	-	-	-	-
Thereafter	3,700	500	300	200
Held-By-Production	152,100	8,000	20,500	5,100
Total	159,100	8,600	84,300	29,200

In general, "royalty" interests are non-operated interests which are not burdened by costs of exploration or lease operations, while "working interests" have operating rights and participate in such costs.

Drilling

The following tables set forth the number of gross and net oil and gas wells in which the company has participated and the results thereof for the periods indicated.

		Gross Wells					
Year Ended	Total Gross	Exploratory			Development		
October 31,	Wells	Oil	Gas	Dry	Oil	Gas	Dry
2007	**24**	**5**	**11**	**7**	**-**	**1**	**-**
2006	27	1	9	13	1	3	-
2005	26	-	10	2	-	14	-

		Net Wells					
Year Ended	Total Net	Exploratory			Development		
October 31,	Wells	Oil	Gas	Dry	Oil	Gas	Dry
2007	**8.591**	**1.166**	**4.143**	**2.700**	**-**	**0.582**	**-**
2006	10.421	0.300	3.184	5.029	0.306	1.602	-
2005	4.683	-	3.075	0.208	-	1.400	-

Insurance

The company believes that its existing insurance coverage is adequate to protect it from the risks associated with the ongoing operation of its business. This coverage includes commercial property, liability and auto, workers compensation, inland marine and excess liability.

Facilities and Employees

The company's corporate headquarters are located at 1801 Broadway, Suite 900, Denver, Colorado, in approximately 4,000 square feet occupied under a lease. The company believes that this space is adequate for its current needs. The company's current lease expires in April 2011.

As of October 31, 2007, the company had 12 employees. None of the company's employees is subject to a collective bargaining agreement, and the company considers relations with its employees to be good.

Company Website

Information related to the following items, among other information, can be found on the company's website at www.credopetroleum.com: (a) company filings with the Securities and Exchange Commission, (b) company press releases, (c) officers, directors and ten percent shareholders filings on Forms 3, 4 and 5, and (d) the company's Code of Ethics and Audit Committee Charter. The company's website is not a part of, or incorporated by reference in, this Annual Report on Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

From time to time, the company may be involved in litigation relating to claims arising out of the company's operations in the normal course of business. As of the date of this Annual Report on Form 10-K, the company is not a party to any pending legal proceedings. No such proceedings have been threatened and none are contemplated by the company.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2007.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

The company's common stock is traded on the NASDAQ Global Market℠ under the symbol "CRED". Market quotations shown below were reported by the Financial Industry Regulatory Authority (FINRA) and represent prices between dealers excluding retail mark-up or commissions and may not necessarily represent actual transactions.

	2007		2006	
Quarter Ended	**High**	**Low**	High	Low
January 31	**$ 13.27**	**$ 11.55**	$ 30.46	$ 17.16
April 30	**$ 16.00**	**$ 11.58**	$ 29.97	$ 20.46
July 31	**$ 14.60**	**$ 11.78**	$ 25.40	$ 16.85
October 31	**$ 11.92**	**$ 9.52**	$ 22.02	$ 12.86

At January 4, 2008, the company had 2,621 shareholders of record. The company has never paid a cash dividend and does not expect to pay any cash dividends in the foreseeable future. Earnings are reinvested in business activities.

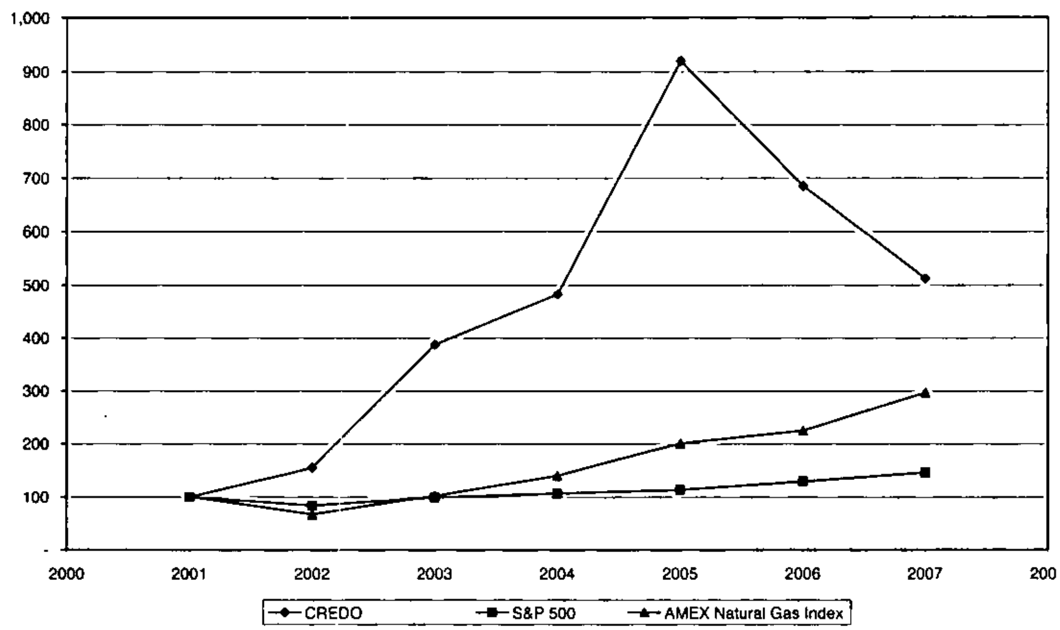
Issuer Purchases of Equity Securities.

During the fourth quarter of the fiscal year, the company repurchased 50,000 shares of its common stock on the open market at a weighted average price of $10.13. The purchase was made pursuant to a stock repurchase plan announced on October 4, 2007. The plan authorized repurchases up to $1,000,000, but could be expanded, suspended or discontinued at any time. No additional shares have been repurchased subsequent to October 31, 2007.

Performance Graph

The following performance graph compares the cumulative total stockholder return on the company's common stock for the six-year period ended October 31, 2007 with the cumulative total return of the AMEX Natural Gas Index, and the Standard & Poor's 500 Stock Index. The identities of the companies included in the index will be provided upon request.

Comparison of 6 Year Cumulative Total Return
October 2007
(Assumes Initial Investment of $100)



	October 31						
	2001	2002	2003	2004	2005	2006	2007
CREDO Petroleum Corporation	$100	$156	$388	$483	$919	$685	$512
Standard & Poor's 500 Stock Index	100	84	99	107	114	130	146
AMEX Natural Gas Index	100	67	102	141	201	225	297

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth certain financial information with respect to the company and is qualified in its entirety by reference to the historical financial statements and notes thereto of the company included in Item 8, "Financial Statements and Supplementary Data." The statement of operations and balance sheet data included in this table for each of the five years in the period ended October 31, 2007 were derived from the audited financial statements and the accompanying notes to those financial statements.

	Years Ended October 31,				
	2007	2006	2005	2004	2003
Audited Financial Information					
Statement of Operations Data:					
Oil and gas sales	**$ 16,174,000**	$ 15,837,000	$ 13,143,000	$ 9,367,000	$ 7,494,000
Investment and other income	**819,000**	654,000	146,000	343,000	461,000
Oil and gas production expense	**3,375,000**	3,407,000	2,759,000	2,075,000	1,608,000
Depreciation, depletion and amortization	**3,666,000**	3,642,000	2,402,000	1,747,000	1,333,000
General and administrative	**1,397,000**	1,291,000	1,117,000	1,171,000	1,315,000
Interest expense	**26,000**	42,000	37,000	39,000	46,000
Income before income taxes and cumulative effect of change in accounting principle	**8,529,000**	8,109,000	6,974,000	4,678,000	3,653,000
Net income	**6,091,000**	5,880,000	5,022,000	3,368,000	2,702,000
Net income per share(1):					
Basic	**$ 0.66**	$ 0.64	$ 0.55	$ 0.37	$ 0.30
Diluted	**$ 0.65**	$ 0.62	$ 0.54	$ 0.36	$ 0.30
Weighted-average shares outstanding(1):					
Basic	**9,280,000**	9,207,000	9,080,000	9,036,000	8,869,000
Diluted	**9,395,000**	9,482,000	9,367,000	9,282,000	9,042,000
Balance Sheet Data:					
Working capital	**12,511,000**	10,073,000	7,697,000	5,611,000	6,577,000
Total assets	**55,349,000**	47,759,000	37,844,000	30,976,000	23,572,000
Long-term obligations:					
Deferred income taxes-net	**9,204,000**	8,039,000	5,978,000	4,605,000	3,192,000
Asset retirement obligation	**1,016,000**	954,000	929,000	748,000	238,000
Exclusive license agreement obligation	**85,000**	163,000	233,000	297,000	355,000
Stockholders' equity	**41,140,000**	34,767,000	26,947,000	20,920,000	17,635,000
Unaudited Operating Data					
Production Volumes:					
Gas (Mcf)	**1,926,000**	2,176,000	1,830,000	1,710,000	1,449,000
Oil (Bbls)	**51,000**	41,000	37,000	41,000	35,000
Mcfe	**2,234,000**	2,422,000	2,050,000	1,960,000	1,660,000
Average sales price before hedging:					
Per Mcf	**$ 5.79**	$ 6.24	$ 6.55	$ 5.02	$ 4.57
Per Bbls	**$ 60.95**	$ 61.14	$ 50.90	$ 36.57	$ 27.68
Average sales price after hedging:					
Per Mcf	**$ 6.78**	$ 6.11	$ 6.16	$ 4.60	$ 4.50
Per Bbls	**$ 60.95**	$ 61.14	$ 50.90	$ 36.57	$ 27.68
Reserves:					
Gas (Mcf)	**16,973,000**	16,005,000	15,516,000	15,273,000	13,786,000
Oil (Bbls)	**591,000**	422,000	386,000	407,000	385,000
Mcfe	**20,517,000**	18,537,000	17,835,000	17,717,000	16,097,000
Estimated future net revenues	**$ 101,501,000**	$ 84,861,000	$ 136,878,000	$77,612,000	$45,165,000
Estimated future net revenues discounted at 10%	**$ 62,071,000**	$ 52,328,000	$ 81,209,000	$44,551,000	$28,024,000

(1) The effect of the three for two stock splits in 2005 and 2004, and 20% stock dividend in 2003, are reflected in all historical share and per share data.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Liquidity and Capital Resources

At October 31, 2007, working capital increased 24% to $12,511,000, compared to $10,073,000 at October 31, 2006. For the year ended October 31, 2007, net cash provided by operating activities was $11,674,000 compared to $12,973,000 for the same period in 2006. The difference is primarily due to a decrease in non-cash items (DD&A, deferred income taxes and other items) of $226,000, an increase in short term investments of $759,000 in 2007 compared to $129,000 in 2006 and net changes in other operating assets. For the year ended October 31, 2007 and 2006, net cash used in investing activities was $8,750,000 and $11,096,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $9,144,000 and $11,746,000, respectively. Financing activities primarily included the purchase of treasury stock of $506,000 and proceeds from exercise of stock options of $368,000 and $835,000 in 2007 and 2006, respectively.

The company's earnings before interest, taxes, depreciation, depletion and amortization, ("EBITDA") increased 4% to $12,221,000 for the year ended October 31, 2007 from $11,793,000 for the prior year. 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:

	For The Year Ended October 31,		
	2007	2006	2005
RECONCILIATION OF EBITDA:			
Net Income	**$ 6,091,000**	$ 5,880,000	$ 5,022,000
Add Back:			
Interest Expense	**26,000**	42,000	37,000
Income Tax Expense	**2,438,000**	2,229,000	1,952,000
Depreciation, Depletion and Amortization Expense	**3,666,000**	3,642,000	2,402,000
EBITDA	**$ 12,221,000**	$11,793,000	$ 9,413,000

The average return on the company's investments for the year ended October 31, 2007 and 2006 was 11.0% and 8.4%, respectively. At October 31, 2007, approximately 46% 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 requirements for at least the next 12 months. At October 31, 2007, the company had no lines of credit or other bank financing arrangements except for the hedging line of credit discussed in Note 1 to the Consolidated Financial Statements. 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.

As of October 31, 2007, the company had the following known contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Exclusive license obligation	$ 163,000	$ 77,000	$ 86,000	$ -	$ -
Operating lease obligations	110,000	32,000	63,000	15,000	-
Total	$ 273,000	$ 109,000	$ 149,000	$ 15,000	$ -

Off-Balance Sheet Financing

The company has no off-balance sheet financing arrangements at October 31, 2007.

Product Prices and Production

Refer to Item 1., "Markets and Customers", for discussion of oil and gas prices and marketing.

Oil and natural gas sales volume and price realization comparisons for the indicated years ended October 31 are set forth below. Price realizations include hedging gains and losses.

	2007		2006		2005	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**1,926,000**	**$ 6.78**(1)	2,176,000	$ 6.11(2)	1,830,000	$ 6.16(3)
% change	**-11%**	**+11%**	+19%	-1%	+7%	+34%
Oil (bbls)	**51,000**	**$ 60.95**	41,000	$ 61.14	37,000	$ 50.90
% change	**+24%**	**00%**	+11%	+20%	-10%	+39%

(1) Includes $0.99 Mcf hedging gain.
(2) Includes $0.12 Mcf hedging loss.
(3) Includes $0.39 Mcf hedging loss.

Significant Properties (see definition on page 12) contributed 62% of 2007 production on a gas-equivalent basis. Increases in oil volumes resulted primarily from successful drilling in Kansas.

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 designated 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 hedges (consisting solely of cash flow hedges) on its balance sheet at fair value at the end of each period. Changes in the fair value of the effective portion 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.

Changes in the fair value of the ineffective portion of cash flow hedges are reported currently in earnings as oil and gas sales during the period that the hedge is ineffective. Ineffective cash flow hedges have not been material in the three years ended October 31, 2007. The company had hedging gains of $1,909,000 in fiscal 2007 and losses of $266,000 in fiscal 2006 and $719,000 in fiscal 2005.

Open hedge contracts at October 31, 2007 are indexed to the NYMEX and are represented by short positions. Actual price realizations in the company's principal areas of operations (primarily Oklahoma) are expected to be 10% to 12% below NYMEX prices primarily due to basis differentials.

Realized (November 2007) and unrealized (December 2007 through September 2008) gains and losses on hedge contracts at October 31, 2007 totaled a $443,000 gain and were included in "Other Comprehensive Income". These contracts covered 1,620 MMBtus at NYMEX basis prices ranging from $7.65 to $9.92.

As of December 31, 2007, hedges covering the contract months of November 2007 through January of 2008 had been closed at expiration resulting in a gain of $847,000. Such hedges covered 430 MMBtus at NYMEX basis prices ranging from $8.70 to $9.92. Open hedge positions as of December 31, 2007, are set forth below.

Commodity	Period Covered	Volume	Average Price NYMEX Basis
Natural Gas	February 2008	150 MMbtu	$ 9.52
Natural Gas	March 2008	140 MMbtu	$ 9.28
Natural Gas	April 2008	150 MMbtu	$ 7.83
Natural Gas	May 2008	150 MMbtu	$ 7.83
Natural Gas	June 2008	150 MMbtu	$ 7.92
Natural Gas	July 2008	150 MMbtu	$ 8.01
Natural Gas	August 2008	150 MMbtu	$ 8.07
Natural Gas	September 2008	150 MMbtu	$ 8.05

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 $5,900,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that 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 funded debt in excess of $500,000. The line expires November 15, 2010.

Oil and Gas Activities

Capital Spending. Capital spending, net of sales, in 2007 totaled $8,808,000, consisting primarily of additions to oil and gas properties, excluding the change in the company's asset retirement related asset.

Operations

Summary – During 2007, the company's operations were focused on its two core projects -- drilling in the Mid-Continent area of the U.S. and application of its Calliope Gas Recovery System. During the past several years, the company has significantly expanded the volume and breadth of its drilling activities by diversifying geographically, scientifically, and in terms of capital, risk and reserve potential. The company has also implemented a program to increase the volume of its Calliope applications by joint venturing with other companies.

Production casing has been set on three wells that were drilling over fiscal year end, and the wells are in the process of being tested and completed. Subsequent to year end, 13 wells commenced drilling, of which three are currently drilling, two are producing, five are being tested or completed for production, and three are dry holes. Four of the wells were drilled in northwest Oklahoma, all of which have been, or are in the process of being, completed for production. One well is currently drilling in Oklahoma. Five of the wells were drilled in central Kansas of which one is producing, one is awaiting completion for production, and three were dry holes. One well is currently drilling in central Kansas. One well was drilled in South Texas and is awaiting pipeline connection, and one well is drilling in North Texas. In addition to follow-up drilling that will be generated by the new wells, 14 additional wells are currently scheduled on prospects in Oklahoma, central Kansas and South Texas. The scheduled wells include a high potential well in South Texas to test the Wilcox formation at 17,500 feet. A high potential well in North Texas is currently drilling toward 11,200 feet.

Also subsequent to fiscal year end, the company has continued to discuss possible joint ventures with other companies for its Calliope Gas Recovery System. One joint venture agreement has been executed and another is in the drafting stage. Several are in the discussion stage.

These activities are discussed in greater detail below.

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. However, it should be expected that successful results will occur unevenly for both the drilling and Calliope projects. Drilling results are dependent on both the timing of drilling and on the drilling success rate. Calliope results are primarily dependent on the timing, volume and quality of Calliope installations available to the company.

The company will continue to actively pursue adding reserves through its two core projects in fiscal 2008, 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 gas recovery system on low pressure gas wells. The prevailing price of oil and natural gas has a significant effect on demand and, thus, the related cost of such services and wells.

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

Drilling Activities

Northern Anadarko Basin – The company owns a significant inventory of acreage (approximately 70,000 gross acres) located along the northern portion of the Anadarko Basin where it conducts an active drilling program. Wells generally target the Morrow, Oswego and Chester formations between 7,000 and 11,000 feet. The company expects to drill a substantial number of additional wells on this acreage.

In Hemphill County, Texas, the 11,200-foot wildcat well drilled in fiscal 2007 to test the 3,780 gross acre Humphreys Prospect encountered excellent quality Morrow sands, and tested at the rate of 3.0 MMcf per day. However, production declined rapidly but stabilized at 150 Mcf per day. The stabilized production rate suggests that the first well is indirectly connected to a larger Morrow reservoir. The company subsequently purchased and reprocessed 3-D seismic over the prospect, and believes that it has identified the primary Morrow channel. A second well has commenced to test the seismic interpretation. The company owns a 25% working interest. This is an expensive but high potential well that, if successful, could have a material positive effect on the company's production in 2008.

In Canadian County, Oklahoma, the 640 gross acre Loosen Prospect continues to yield excellent drilling results from the Redfork and Skinner formations. The 11,500-foot Marcia #1-14 is currently drilling and is the fifth well drilled on the prospect. The Marcia well is a north extension to the recently completed Chappell well which encountered pay zones in five separate formations. The well is currently completed in three of the five zones and is producing 1.9 MMcf and 30 barrels of oil per day. The remaining zones will be opened for production at a later date. The Chappell well was a north extension to the Hazel well, drilled in December 2006, which is still producing 2.0 MMcf (million cubic feet of gas) and about 20 barrels of oil per day. The company owns working interests in the new wells as follows: Hazel -- 6.25%; Chappell -- 16.3%, Marcia -- 14.5%.

In Harper County, Oklahoma, the 3,840 gross acre Buffalo Creek Prospect continues to be a very active drilling area for the company based on a recently completed 3-D seismic program. Nine wells have now been completed on the prospect with production from the Chester, Morrow and Oswego formations. The most recent well encountered 14 feet of excellent Morrow sand porosity that electric logs indicate is productive. The well is currently being completed. The company owns working interests in the prospect ranging from 31% to 37%. Three to five new drilling locations are currently planned for 2008, and more are expected based on the results of future wells.

In Ellis County, Oklahoma, the first well has been drilled on the company's 2,560 gross acre North Boxer Prospect. The 8,500-foot well is currently classified as a "tight hole", meaning information is not being released for proprietary business reasons. A second wildcat well has been drilled about one mile to the south and is currently being completed. The company owns working interests in the prospect ranging from 30% to 40%.

In Kingfisher County, Oklahoma, the first two wells have been drilled on the 1,280 gross acre Okarche Prospect to test the Hunton, Meramec, Chester and Redfork formations. Both wells are currently awaiting completion. The company owns working interests ranging from 9.5% to 11%.

In Carter County, Oklahoma, the Southeast Hewitt Waterflood Unit has produced over 600,000 incremental barrels of oil, significantly outperforming initial expectations. As a result of development drilling, production from the unit has recently increased about 40% to 270 barrels of oil per day. Further development is under consideration. The company owns a 17% working interest.

In Love County, Oklahoma, a new waterflood project is currently in the initial stages of operations. The company owns a 10% to 12% working interest in various phases of the project.

South Texas – The company has recently expanded the volume and breadth of its exploration program with new drilling projects in South Texas. These projects diversify the company's exploration geographically, scientifically, and in terms of capital, risk and reserve potential. Compared to the company's Oklahoma drilling, the South Texas project involves higher costs and greater risks but offers significantly higher per well production and reserve potential.

The most significant of the two South Texas projects is 3-D seismic driven and focuses on the Vicksburg, Frio and Queen City sands in Hidalgo County and the Wilcox sands in Jim Hogg County at depths ranging from 7,200 feet to 17,500 feet. To date, the company has invested approximately $1,872,000 (net) in the project, exclusive of drilling. Prior to sale or farmout of the prospects, the company owns a 75% interest before recovery of its investment, exclusive of drilling, and 37.5% thereafter. The company has the option to participate in drilling any of the prospects for its full interest or to reduce its costs and risks by selling or farming-out its interest to third parties in return for cash consideration and a "carried interest" on the initial wildcat well(s).

The primary objective of this project has been identification of, leasing and sale of three "deep Wilcox" prospects located in Jim Hogg County. The prospects cover 3,600 gross acres, range in depth from 16,500 to 17,500 feet, and are located in an area where several nearby fields have produced hundreds of billions of cubic feet of gas from the Wilcox formation.

The company's 3-D seismic interpretation indicates that the prospects are large enough in size to have very substantial production and reserve potential in relation to the company's existing production and reserves. However, the prospects are high risk, rank wildcat prospects and per well drilling costs far exceed those normally incurred by the company. Therefore, the company has elected to sell a portion of its interest for cash consideration and a "carried interest" on two initial wildcat wells. Third parties have committed to purchase the three prospects and to drill a wildcat well on one prospect. The second wildcat well is optional based on the outcome of the first well. Paperwork is in the process of being completed. The operator has indicated the intent to commence drilling early in 2008. In addition to recovering a significant portion its cash investment in the project and being "carried" for an interest in the initial test well(s), the company has preserved its option to participate in other wells drilled on the prospects with interests ranging from 18% before recovery of its investment to 9% after recovery. If drilling is successful, the company expects that its retained interest in the prospects will have a very significant impact on its production and reserve growth.

Elsewhere in South Texas, the first well has been drilled on the 2,500 gross acre Briggs Ranch Prospect located in Victoria County. The prospect is fault separated from the Heyser Field which has produced 738,000 barrels of oil and 17 Bcf from the Frio sands. The 8,600-foot Briggs Ranch #1 encountered 11 feet of Frio sands that electric logs indicate are productive. The well has been completed and is awaiting pipeline connection. The company owns a 9% working interest.

North-Central Kansas – The company further expanded the volume and breadth of its exploration program with a new drilling project in central Kansas. The Kansas project provides diversification to the company's drilling program geographically and scientifically through the use of 3-D seismic to identify shallow oil prospects. The acreage is located in prolific oil producing areas where 3-D seismic has proven effective in identifying satellite structures near mature producing fields. Higher oil prices have justified using 3-D seismic technology to locate undrilled structures that are very difficult to find with old technology. Drilling targets the Lansing-Kansas City and Arbuckle formations at about 4,000 feet and, compared to the company's Northern Anadarko Basin and South Texas projects, is relatively low cost, low risk, and exclusively targets oil reserves in an effort to bring better product balance to the company's reserve base. The company has assembled four separate drilling projects which encompass about 41,000 gross acres and is continuing to seek opportunities to increase its exposure to the play. The company owns working interests in the existing prospects ranging from 12.5% to 75%.

The company's recent drilling results have improved dramatically as it continues to find the keys to successful seismic and geologic interpretation. Four of the last seven wells have been completed as producers, and three of those appear to be outstanding wells.

In Graham County, a wildcat well has been completed on the 3,280 gross acre White Anticline prospect. The well encountered excellent porosity in the Lansing-Kansas City limestone and is producing 100 barrels of oil per day. A second well on the prospect resulted in a dry hole. In the same area, the first well on the 4,900 gross acre Mount Vernon prospect encountered Lansing-Kansas City limestone that appears from tests and electric logs to be productive. The well is currently being completed and has swab tested at rates in excess of 150 barrels of oil per day. The company owns a 12.5% working interest in both prospects.

In Sheridan County, a wildcat well has been successfully completed on the company's 20,000 gross acre Lucerne Prospect. The new well is located in the same general area as the previously reported Ficken #1-23 which has been an excellent well, having produced about 35,000 barrels of oil in 12 months. The new well encountered productive Lansing-Kansas City limestone and is producing about 40 barrels of oil per day. Also in Sheridan County, a new well has been drilled on the St. Peter North prospect and is awaiting completion after an excellent recovery on drillstem test. The company owns a 30% working interest in both wells.

Calliope Gas Recovery Technology

The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. There are currently three U.S. patents and two Canadian patents related to the technology. One additional patent that mirrors the U.S. patents has been applied for in Canada. Calliope systems are installed on wells located in Oklahoma, Texas and Louisiana.

Calliope can achieve substantially lower flowing bottom-hole pressure than other production methods because it does not rely on reservoir pressure to lift liquids. In many reservoirs, 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 is implementing strategies designed to expand the population of wells on which it can install Calliope.

Calliope's Track Record – At fiscal year end, Calliope had been installed on 25 wells located in Oklahoma, Texas and Louisiana. The Calliope wells produce from both sandstone and carbonate reservoirs including the Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Redfork and Springer formations. The Calliope wells range in depth from 6,400 to 18,400 feet. These wells represent rigorous applications for Calliope because at the time Calliope was installed, 14 of the wells were dead (an average of two to three years), nine were uneconomic and two were marginal. In addition, prior to the time Calliope was installed, many of the reservoirs were damaged by the "parting shots" of previous operators. Twenty-three of the wells were acquired from other operators after the operators had given-up on these wells. The previous operators were mostly medium to large independent oil and gas companies.

Initial Calliope production rates range up to 650 Mcfd and average per well Calliope reserves for non-experimental wells are estimated to be 1.0 Bcf. One of the company's early Calliope installations, the J.C. Carroll well, has now produced over a billion cubic feet of gas using Calliope.

The 25 Calliope applications are grouped into two categories – experimental wells and non-experimental wells, also referred to as "go-forward" applications. Eleven of the 25 wells are experimental applications and 14 are go-forward applications. Experimental wells generally represent the first experimental application of a Calliope configuration in a wellbore. For example, the first installation of Calliope inside a particular tubing size is classified as an experimental application.

Calliope has achieved compelling results on these less than ideal wells as is shown in the table below. For example, the entire group of 14 non-experimental wells were producing a total of only 88 Mcfd when Calliope was installed. Without Calliope, the wells represented a substantial plugging liability. However, with Calliope, those same 14 wells have now produced an incremental 3.4 Bcfe to date, and they are still producing about 2.0 MMcfed. With Calliope, the 14 wells were projected to have estimated ultimate incremental Calliope reserves totaling 13.6 Bcfe.

Group	No. of Wells	Average Calliope Reserves Per Well (Bcfe)	Total Calliope Production to Date (Bcfe)	Total Projected Calliope Reserves (Bcfe)
Non-Experimental Wells	**14**	**1.0**	**3.4**	**13.6**
Experimental Wells	11	0.2	0.6	1.4
All Wells	25	0.6	4.0	15.0

Calliope has proven to be a low risk and low cost liquid lift technology. Calliope has never failed to lift the liquids out of a wellbore. The average cost of a Calliope system is $400,000 for a 12,000-foot application. Based on average per well Calliope reserves of 1.0 Bcfe for go-forward applications, cost of Calliope in terms of units of natural gas reserves added is low compared to industry averages. Based on current natural gas prices, Calliope can economically be installed on wells which will yield significantly less than 1.0 Bcf of Calliope reserves. This will enable the company to significantly expand the range of Calliope applications to include many low permeability reservoirs, possibly including those in shale and other "resource plays".

Realizing Calliope's value continues to be one of the company's top priorities. The company has been 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.

Purchasing Calliope Candidate Wells – Calliope operations were expanded into Texas and Louisiana in fiscal 2006. The company considers Texas and Louisiana to be very fertile areas for Calliope and has retained personnel and opened a Houston office to focus exclusively on purchasing wells for Calliope and on Calliope joint ventures.

In general, higher natural gas prices have made it increasingly difficult for the company to purchase wells for its Calliope system. In addition, higher gas prices have provided the incentive for other companies to perform high risk procedures ("parting shots") in an attempt to revive wells prior to abandoning or selling the wells. These parting shots often result in severe reservoir damage that renders wells unsuitable for Calliope. Accordingly, viable Calliope candidate wells available to be purchased by the company have been very restricted.

Joint Ventures With Third Parties – In an effort to increase the number of Calliope installations, the company has been discussing joint ventures with larger companies. Presentations have been made to a select group of companies, including majors and large independents. All of the companies have expressed an interest in Calliope. Two joint venture agreements were completed during 2007, one agreement is presently in the drafting stage, and joint venture discussions are in progress with a number of the companies, including evaluation of candidate wells.

The joint venture negotiation process has taken longer than expected because there are many decision points within large companies that cause delays. Nevertheless, the company continues to dedicate substantial resources to joint venture projects, as it believes that the company will eventually be successful in the joint venture area.

Calliope Drilling Project – The company believes that there is a huge amount of gas stranded in abandoned and low pressure reservoirs that can be recovered using Calliope. It believes drilling new wells for Calliope into such reservoirs will provide a repeatable opportunity to lease large areas for systematic re-development. In addition, new wells allow optimum casing and tubular sizes to be installed which will substantially improve reserves and production compared to installing Calliope on existing wells where undersized tubulars often restrict Calliope's optimum performance.

In June 2007, the company entered into a joint venture to purchase an 11,000-foot well located in East Texas. The previous operator drilled the well and encountered low reservoir pressure. After unsuccessful attempts to make the well produce, the operator sold the well to the company joint venture for $65,000 (salvage value). Calliope was installed and immediately brought the well to life, producing at the rate of 250 Mcf per day. The well provided a successful test of the Calliope drilling concept and demonstrated that Calliope will successfully solve liquid loading problems that are difficult, if not impossible, to address with other liquid lift technologies.

During 2006, the company entered into a 50/50 joint venture with a private company to drill wells for the purpose of using Calliope to recover stranded gas reserves. The joint venture committed the company to an exclusive "project area" with the joint venture partner that covered much of South and East Texas. The terms of the agreement provided for an activity threshold of at least three wells in the first year, and that either party could terminate the agreement at the end of the first year if the threshold was not met. As of the first anniversary of the agreement, no wells had been drilled and the company elected to terminate the agreement because it believed that the company's interest would be better served to open the extensive project area covered by the agreement to other Calliope drilling opportunities. There were no cancellation penalties.

Reserves. Refer to Item 2, "Properties, Significant Properties, Estimated Proved Oil and Gas Reserves and Future Net Revenues", for information regarding oil and gas reserves.

Results of Operations

In 2007, total revenues increased 3% to $16,993,000 compared to $16,491,000 last year. As the oil and gas price/volume table on page 20 shows, total gas price realizations, which reflect hedging transactions, increased 11% to $6.78 per Mcf and oil price realizations fell to $60.95 per barrel. The net effect of these price changes was to increase oil and gas sales by $989,000. Hedging gains were $1,909,000 in 2007 compared to losses of $266,000 in 2006. During the same period, the company's gas equivalent production fell 8% resulting in a decrease in oil and gas sales of $849,000. Investment and other income increased primarily due to improved performance from the company's investments.

In 2007, total costs and expenses rose 1% to $8,464,000 compared to $8,382,000 for last year. Oil and gas production expenses fell 1% due primarily to reduced taxes associated with lower production. General and administrative expenses increased 8% primarily due to increases in professional fees related to compliance with Sarbanes-Oxley regulations. Interest expense relates to the Calliope exclusive license agreement note payment. The effective tax rate was 28.5% and 27.5% for the 2007 and 2006 periods, respectively.

In 2006, total revenues increased 24% to $16,491,000 compared to $13,289,000 in 2005. As the oil and gas price/volume table on page 20 shows, total gas price realizations, which reflect hedging transactions, fell 1% to $6.11 per Mcf and oil price realizations increased 20% to $61.14 per barrel. The net effect of these price changes was to increase oil and gas sales by $300,000. Hedging losses were $266,000 in 2006 compared to $719,000 in 2005. During the same period, the company's gas equivalent production increased 18% resulting in an increase to oil and gas sales of $2,394,000. Investment and other income increased primarily due to improved performance from the company's investments.

In 2006, total costs and expenses rose 33% to $8,382,000 compared to $6,315,000 for in 2005. Oil and gas production expenses rose 23% due primarily to increased production taxes on higher revenues and new wells added during the year. Depreciation, depletion and amortization ("DD&A") increased 52% due to increased production volumes and an increase in costs being amortized. General and administrative expenses rose 16% primarily due to increases in professional fees related to compliance with Sarbanes-Oxley regulations and accelerated filing requirements for SEC financial reports. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 27.5% and 28.0% for the 2006 and 2005 periods, respectively.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires the company 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. 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 natural 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.

The company has made only one ceiling write-down in its 29-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.

The company's reserves, and reserve values, are concentrated in 61 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2007, the Significant Properties represent 26% of the company's total properties but a disproportionate 77% 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 20% of the Significant Properties and represent 22% of the discounted reserve value of such properties. New wells comprise 16% of the Significant Properties and represent 15% 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.

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 fiscal year end 2007 by production for fiscal year 2007. This measure yields an average reserve life of 9 years. 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.

Asset Retirement Obligations. Statement of Financial Accounting Standards ("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.

Recent Accounting Pronouncements

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109 ("FIN 48").* This interpretation clarifies the application of SFAS 109 by defining the criterion than an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements and also provides guidance on measurement, de-recognition, classification, interest and penalties, accounting in interim periods and disclosure. FIN 48 is effective for our fiscal year commencing November 1, 2007. The adoption of FIN 48 is not expected to have an impact on the company's results of Operations or Financial Condition.

In November 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combination* (FAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (FAS 160). FAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. FAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. FAS 141(R) and FAS 160 are effective for both public and private companies for fiscal years beginning on or after December 15, 2008 (fiscal 2010 for the Company). FAS 141(R) will be applied prospectively. FAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of FAS 160 will be applied prospectively. Early adoption is prohibited for both standards. Management is currently evaluating the requirements of FAS 141(R) and FAS 160 and has not yet determined the impact on its financial statements.

In December, 2007 the FASB issued FSAS No.157, *Fair Value Measurements*. This Statement does not require any new fair value measurements, but rather, it provides enhanced guidance to other pronouncements that require or permit assets or liabilities to be measured at fair value. However, the application of this Statement may change how fair value is determined. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. As of December 1, 2007 the FASB has proposed a one-year deferral for the implementation of the Statement for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. Management is currently evaluating the requirements of FAS 159 and has not yet determined the impact on its financial statements.

In December, 2007 the FASB issued FSAS No.159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115.* This Statement provides all entities with an option to report selected financial assets and liabilities at fair value. The Statement is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007, with early adoption available in certain circumstances. Management is currently evaluating the requirements of FAS 159 and has not yet determined the impact on its financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The company manages exposure to commodity price fluctuations by periodically hedging a portion of estimated natural gas 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements **Page**

CONSOLIDATED BALANCE SHEETS
October 31, 2007 and 2006

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

ASSETS	2007	2006
Current assets:		
Cash and cash equivalents	**$ 7,285,000**	$ 4,577,000
Short-term investments	**6,383,000**	5,624,000
Receivables:		
Trade	**602,000**	777,000
Accrued oil and gas sales	**1,647,000**	1,963,000
Derivative assets	**443,000**	897,000
Other current assets	**55,000**	71,000
Total current assets	**16,415,000**	13,909,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**7,791,000**	7,060,000
Evaluated oil and gas properties	**51,691,000**	43,588,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(22,108,000)**	(18,556,000)
Net oil and gas properties	**37,374,000**	32,092,000
Exclusive license agreement, net of accumulated amortization of $501,000 in 2007 and $431,000 in 2006	**198,000**	268,000
Compressor and tubular inventory to be used in development	**1,090,000**	1,293,000
Other, net	**272,000**	197,000
Total assets	**$ 55,349,000**	$ 47,759,000
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 1,639,000**	$ 1,581,000
Revenue distribution payable	**979,000**	1,273,000
Other accrued liabilities	**852,000**	808,000
Income taxes payable	**434,000**	174,000
Total current liabilities	**3,904,000**	3,836,000
Long-term liabilities:		
Deferred income taxes, net	**9,204,000**	8,039,000
Exclusive license obligation, less current obligations of $77,000 in 2007 and $70,000 in 2006	**85,000**	163,000
Asset retirement obligation	**1,016,000**	954,000
Total liabilities	**14,209,000**	12,992,000
Commitments:		
Stockholders' equity:		
Preferred stock, no par value, 5,000,000 shares authorized, none issued	**-**	-
Common stock, $.10 par value, 20,000,000 shares authorized, 9,510,000 shares issued in 2007 and 2006	**951,000**	951,000
Capital in excess of par value	**15,913,000**	14,794,000
Treasury stock, at cost, 215,000 shares in 2007, and 249,000 shares in 2006	**(506,000)**	-
Accumulated other comprehensive income	**319,000**	650,000
Retained earnings	**24,463,000**	18,372,000
Total stockholders' equity	**41,140,000**	34,767,000
Total liabilities and stockholders' equity	**$ 55,349,000**	$ 47,759,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three Years Ended October 31, 2007

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2007	2006	2005
Revenues:			
Oil and gas sales	**$ 16,174,000**	$ 15,837,000	$ 13,143,000
Investment and other income	**819,000**	654,000	146,000
	16,993,000	16,491,000	13,289,000
Costs and expenses:			
Oil and gas production	**3,375,000**	3,407,000	2,759,000
Depreciation, depletion and amortization	**3,666,000**	3,642,000	2,402,000
General and administrative	**1,397,000**	1,291,000	1,117,000
Interest	**26,000**	42,000	37,000
	8,464,000	8,382,000	6,315,000
Income before income taxes	**8,529,000**	8,109,000	6,974,000
Income taxes	**(2,438,000)**	(2,229,000)	(1,952,000)
Net income	**$ 6,091,000**	$ 5,880,000	$ 5,022,000
Basic income per share	**$ .66**	$ .64	$ .55
Diluted income per share	**$ .65**	$ .62	$ .54
Weighted average number of shares of common stock and dilutive securities:			
Basic	**9,280,000**	9,207,000	9,080,000
Diluted	**9,395,000**	9,482,000	9,367,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Three Years Ended October 31, 2007

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock		Capital In Excess Of	Treasury	Accumulated Other Comprehensive	Retained	Total Stockholders'
	Shares	Amount	Par Value	Stock	Income (Loss)	Earnings	Equity
Balances, October 31, 2004	9,510,000	$ 951,000	$ 13,388,000	$(452,000)	$(437,000)	$ 7,470,000	$20,920,000
Comprehensive income:							
Net income	-	-	-	-	-	5,022,000	5,022,000
Other comprehensive income (loss), net of tax: Change in fair value of derivatives	-	-	-	-	131,000	-	131,000
Purchase of treasury stock	-	-	-	(8,000)	-	-	(8,000)
Exercise of common stock options	-	-	-	335,000	-	-	335,000
Tax benefit from the exercise of common stock options	-	-	340,000	-	-	-	340,000
Compensation expense related to employee stock options	-	-	288,000	-	-	-	288,000
Tax Benefit for FAS 123R Option Expense	-	-	(81,000)	-	-	-	(81,000)
Balances, October 31, 2005	9,510,000	951,000	13,935,000	(125,000)	(306,000)	12,492,000	26,947,000
Comprehensive income:							
Net income	-	-	-	-	-	5,880,000	5,880,000
Other comprehensive income (loss), net of tax: Change in fair value of derivatives	-	-	-	-	956,000	-	956,000
Exercise of common stock options	-	-	710,000	125,000	-	-	835,000
Compensation expense related to employee stock options	-	-	209,000	-	-	-	209,000
Tax Benefit for FAS 123R Option Expense	-	-	(60,000)	-	-	-	(60,000)
Balances, October 31, 2006	9,510,000	951,000	14,794,000	-	650,000	18,372,000	34,767,000
Comprehensive income:							
Net income	-	-	-	-	-	6,091,000	6,091,000
Other comprehensive income (loss), net of tax: Change in fair value of derivatives	-	-	-	-	(331,000)	-	(331,000)
Purchase Treasury Stock	-	-	-	(506,000)	-	-	(506,000)
Exercise of common stock options	-	-	368,000	-	-	-	368,000
Compensation expense related to employee stock options	-	-	153,000	-	-	-	153,000
Tax Benefit from Exercise of Stock Options	-	-	598,000	-	-	-	598,000
Balances, October 31, 2007	9,510,000	$ 951,000	$15,913,000	(506,000)	$ 319,000	$24,463,000	$41,140,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Years Ended October 31, 2007

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2007	2006	2005
Cash flows from operating activities:			
Net income	**$ 6,091,000**	$ 5,880,000	$ 5,022,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**3,666,000**	3,642,000	2,402,000
Deferred income taxes	**1,763,000**	2,001,000	1,292,000
Compensation expense related to stock options granted	**153,000**	209,000	288,000
Other	**62,000**	18,000	-
Changes in operating assets and liabilities:			
Proceeds from short-term investments	**1,544,000**	551,000	2,500,000
Purchase of short-term investments	**(2,303,000)**	(680,000)	(1,624,000)
Trade receivables	**316,000**	226,000	16,000
Accrued oil and gas sales	**175,000**	813,000	(725,000)
Other current assets	**139,000**	234,000	299,000
Accounts payable and accrued liabilities	**(192,000)**	236,000	(968,000)
Income taxes payable	**260,000**	(157,000)	319,000
Net cash provided by operating activities	**11,674,000**	12,973,000	8,821,000
Cash flows from investing activities:			
Additions to oil and gas properties	**(9,144,000)**	(11,746,000)	(6,938,000)
Proceeds from sale of oil and gas properties	**310,000**	670,000	180,000
Changes in other long-term assets	**84,000**	(20,000)	(909,000)
Net cash used in investing activities	**(8,750,000)**	(11,096,000)	(7,667,000)
Cash flows from financing activities:			
Proceeds from exercise of stock options	**368,000**	835,000	335,000
Purchase of treasury stock	**(506,000)**	-	(8,000)
Principal payment on exclusive license obligation	**(78,000)**	(70,000)	(64,000)
Net cash used by financing activities	**(216,000)**	765,000	263,000
Increase in cash and cash equivalents	**2,708,000**	2,642,000	1,417,000
Cash and cash equivalents:			
Beginning of period	**4,577,000**	1,935,000	518,000
End of period	**$ 7,285,000**	$ 4,577,000	$ 1,935,000
Supplemental Cash Flow Information:			
Cash paid during the period for income taxes	**$ 371,000**	$ 620,000	$ 100,000
Cash paid during the period for interest	**$ 26,000**	$ 30,000	$ 36,000

See accompanying notes to consolidated financial statements.

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Presentation

The consolidated financial statements include the accounts of CREDO Petroleum Corporation and its wholly owned subsidiaries (the "company"). The company engages in oil and gas acquisition, exploration, development and production activities in the United States. Certain operations are conducted through limited partnerships and limited liability companies which, as general partner or member company, the company manages and controls. The company's interests in these entities are combined on the proportionate share basis in accordance with accepted industry practice. All significant intercompany transactions have been eliminated. All references to years in these Notes refer to the company's fiscal October 31 year. The company effected a three-for two stock split in each of fiscal 2005 and 2004. All share and per share amounts discussed and disclosed in this Annual Report on Form 10-K reflect the effect of these stock splits.

Cash, Cash Equivalents, and Short-Term Investments

Cash equivalents consist of highly liquid investments with original maturities of three months or less. At October 31, 2007, approximately 46% of short-term investments are mutual funds. Other short-term investments consist primarily of professionally managed limited partnerships which provide readily determinable market values and short-term liquidity. The partnerships are invested primarily in financial instruments. Unrealized gains on limited partnerships are not significant. Short-term investments are classified as "trading" and are stated at fair value with realized and unrealized gains and losses immediately recognized.

Concentration of Credit Risk

Substantially all of the company's receivables are within the oil and natural gas industry, primarily from purchasers of oil and gas and from joint interest owners. These receivables are due from many companies with collectability being dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized. To date the company has had minimal bad debts.

Fair Value of Financial Instruments

The company's financial instruments including cash and cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. Derivatives, consisting solely of cash flow hedges, are carried at fair value on the balance sheet. See Natural Gas Price Hedging on page 38 for further discussions.

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 separate expenses. Revenue is recorded when the month production is delivered to the purchaser at which time title changes hands. Payment is generally received between 30 and 90 days after the date of production. 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.

Accounting Estimates

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 and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom.

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. 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.

The company has made only one ceiling write-down in its 29-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 of 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.

The company's reserves, and reserve values, are concentrated in 61 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2007, the Significant Properties represent 26% of the company's total properties but a disproportionate 77% 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 20% of the Significant Properties and represent 22% of the discounted reserve value of such properties. New wells comprise 16% of the Significant Properties and represent 15% 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.

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 fiscal year end 2007 by production for fiscal year 2007. This measure yields an average reserve life of nine years. 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.

Asset Retirement Obligations.

The company estimates the future cost of asset retirement obligations, discounts that cost to its present value, and records 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. A reconciliation of the company's asset retirement obligation liability is as follows:

	October 31,	
	2007	2006
Beginning asset retirement obligation	**$ 954,000**	$ 929,000
Accretion expense	**36,000**	40,000
Obligations incurred	**46,000**	58,000
Obligations settled	**-**	(58,000)
Change in estimate	**(20,000)**	(15,000)
Ending asset retirement obligation	**$ 1,016,000**	$ 954,000

Depreciation, Depletion and Amortization.

Effective August 1, 2006, the company changed its estimate with respect to estimated salvage value of lease and well equipment. This change in estimate resulted in a decrease in depreciation, depletion and amortization due to an increase in salvage value.

Environmental Matters

Environmental costs are expensed or capitalized depending on their future economic benefit. Costs that relate to an existing condition caused by past operations with no future economic benefit are expensed. Liabilities for future expenditures of a non-capital nature are recorded when future environmental expenditures and/or remediation is deemed probable and the costs can be reasonably estimated. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

Long-Lived Assets

The company applies SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", to long-lived assets not included in oil and gas properties. Under SFAS No. 144, all long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value.

Income Taxes

The company accounts for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes", which requires the use of the asset and liability method of computing deferred income taxes. The objective of the asset and liability method is to establish deferred tax assets and liabilities for the temporary differences between the book basis and the tax basis of the company's assets and liabilities at enacted tax rates expected to be in effect when such amounts are realized or settled.

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 hedges (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 the effective portion 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 are included in oil and gas sales. Changes in the fair value of the ineffective portion of cash flow hedges are reported currently in earnings as oil and gas sales during the period that the hedge is ineffective. Ineffective cash flow hedges have not been material in the three years ended October 31, 2007. The company had hedging gains of $1,909,000 in fiscal 2007 and losses of $266,000 in fiscal 2006, and $719,000 in fiscal 2005.

Open hedge contracts are indexed to the NYMEX. Periodically, the company enters into contracts indexed to Panhandle Eastern Pipeline Company for Texas, Oklahoma mainline. For comparative purposes, hedges indexed to Panhandle Eastern Pipeline Company are expressed on a NYMEX basis. For hedges indexed to Panhandle Eastern Pipeline Company, the individual month price (basis) differentials between the NYMEX and Panhandle Eastern Pipeline Company range from minus $1.45 in the winter months to minus $0.90 in the spring months.

Realized (November 2007) and unrealized (December 2007 through September 2008) gains and losses on hedge contracts at October 31, 2007 totaled a gain of $443,000 ($319,000 after income tax) and were included in "Other Comprehensive Income". These contracts covered 1,620 MMBtus at NYMEX basis prices ranging from $7.65 to $9.92.

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 $5,900,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that 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 funded debt in excess of $500,000. The line expires November 15, 2010.

Stock-Based Compensation

The company's 2007 Stock Option Plan (the "Plan"), was approved by the shareholders at the Annual Meeting of Shareholders on March 22, 2007 and authorizes the granting of incentive and nonqualified options to purchase shares of the company's common stock. The maximum number of shares that may be made subject to grants is 1,000,000. The Plan is administered by the Board of Directors which determines the terms pursuant to which any option is granted. The Plan provides that upon a change in control of the company, options then outstanding will immediately vest and the company will take such actions as are necessary to make all shares subject to options immediately salable and transferable. Plan activity 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. The company's 1997 Stock Option Plan, which was similar in all respects to the 2007 Plan, expired on July 29, 2007. No additional options can be granted under the 1997 Plan. However, all outstanding options granted under the 1997 Plan will continue to be governed by the terms of the 1997 Plan.

The weighted average grant date fair value of the 20,000 options granted to the company's directors during the year ended October 31, 2007 was $4.01. The weighted average grant date fair value for the 20,000 options granted to employees during the year ended October 31, 2007 was $4.93. In each case, the fair value was measured using the Black-Scholes valuation model with the following assumptions: expected stock price volatility of 50.84%; risk free interest rate of 4.58%; no dividends; and an expected future life of 3 years for employees and 2 years for directors.

The fair value of the stock option grants are amortized over the respective vesting period using the straight-line method and assuming no forfeitures.

Compensation expense related to stock options included in General and Administrative Expense for the years ended October 31, 2007, 2006 and 2005 is $153,000, $209,000 and $288,000, respectively. The tax benefit associated with these expenditures was $44,000, $60,000 and $81,000 in fiscal year 2007, 2006 and 2005, respectively. The estimated unrecognized compensation cost from unvested options as of October 31, 2007 was approximately $123,000, which is expected to be recognized over an average period of 2.6 years.

Plan activity for the years ended October 31, 2007, 2006 and 2005 is set forth below and has been adjusted for the 3-for-2 stock splits in fiscal 2005 and 2004.

	Years Ended October 31,					
	2007		2006		2005	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	**315,002**	**$ 5.52**	485,064	$ 5.78	565,875	$ 7.11
Granted........	**40,000**	**12.78**	-	-	33,750	8.93
Exercised......	**(84,187)**	**4.39**	(143,813)	5.81	(61,686)	5.43
Cancelled or forfeited..	**(564)**	**5.93**	(26,249)	8.82	(52,875)	6.01
Outstanding at end of year ..	**270,251**	**$ 6.94**	315,002	$ 5.52	485,064	$ 5.78
Weighted average contractual life at end of year ..		**6.13**		6.40		7.70
Weighted average fair value of grants		**$ 4.47**				$ 6.16
Exercisable at end of year	**236,918**	**$ 6.12**	266,939	$ 5.53	348,114	$ 5.64
Aggregate intrinsic value of Exercisable Options	**$855,000**		$ 1,999,000		$ 4,118,000	

The aggregate intrinsic value of options exercised during fiscal years 2007, 2006 and 2005 was approximately $704,000, $2,227,000 and $250,000, respectively.

The company has issued shares from its treasury stock whenever stock options have been exercised in fiscal years 2007, 2006 and 2005.

The following table summarizes information about stock options outstanding at October 31, 2007:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding at October 31, 2007	Weighted Average Remaining Contractual Life in Year	Weighted Average Exercise Price	Number Exercisable at October 31, 2007	Weighted Average Exercise Price
$ 5.93	230,251	5.62	$ 5.93	230,251	$ 5.93
$12.78	40,000	9.10	$ 12.78	6,667	$ 12.78
$ 5.93-$12.78 ...	270,251	6.13	$ 6.94	236,918	$ 6.12

Per Share Amounts

Basic income per share is computed using the weighted average number of shares outstanding. Diluted income per share reflects the potential dilution that would occur if stock options were exercised using the average market price for the company's stock for the period. Total potential dilutive shares based on options outstanding at October 31, 2007 were 114,597.

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

	Year Ended October 31,								
	2007			2006			2005		
	Net Income	Shares	Net Income Per Share	Net Income	Shares	Net Income Per Share	Net Income	Shares	Net Income Per Share
Basic earnings per share.......	$6,091,000	9,280,000	$.66	$5,880,000	9,207,000	$.64	$5,022,000	9,080,000	$.55
Effect of dilutive shares of common stock from stock options...	-	115,000	(.01)	-	275,000	(.02)	-	287,000	(.01)
Diluted earnings per share.......	$6,091,000	9,395,000	$.65	$5,880,000	9,482,000	$.62	$5,022,000	9,367,000	$.54

Recent Accounting Pronouncements

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109 ("FIN 48")*. This interpretation clarifies the application of SFAS 109 by defining the criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements and also provides guidance on measurement, de-recognition, classification, interest and penalties, accounting in interim periods and disclosure. FIN 48 is effective for our fiscal year commencing November 1, 2007. The adoption of FIN 48 is not expected to have an impact on our results of operations or financial condition.

In November 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combination* (FAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (FAS 160). FAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. FAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. FAS 141(R) and FAS 160 are effective for both public and private companies for fiscal years beginning on or after December 15, 2008 (fiscal 2010 for the Company). FAS 141(R) will be applied prospectively. FAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of FAS 160 will be applied prospectively. Early adoption is prohibited for both standards. Management is currently evaluating the requirements of FAS 141(R) and FAS 160 and has not yet determined the impact on its financial statements.

In December, 2007 the FASB issued FSAS No.157, *Fair Value Measurements*. This Statement does not require any new fair value measurements, but rather, it provides enhanced guidance to other pronouncements that require or permit assets or liabilities to be measured at fair value. However, the application of this Statement may change how fair value is determined. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. As of December 1, 2007 the FASB has proposed a one-year deferral for the implementation of the Statement for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. Management is currently evaluating the requirements of FAS 159 and has not yet determined the impact on its financial statements.

In December, 2007 the FASB issued FSAS No.159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115.* This Statement provides all entities with an option to report selected financial assets and liabilities at fair value. The Statement is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007, with early adoption available in certain circumstances. Management is currently evaluating the requirements of FAS 159 and has not yet determined the impact on its financial statements.

(2) COMMON STOCK AND PREFERRED STOCK

The company has authorized 20,000,000 shares of $0.10 par value common stock and as of October 31, 2007, common shares issued are 9,510,000, common shares held in treasury are 215,000 and common shares outstanding are 9,295,000. In addition, the company has authorized 5,000,000 shares of preferred stock which may be issued in series and with preferences as determined by the company's Board of Directors. Approximately 100,000 shares of the company's authorized but unissued preferred stock have been reserved for issuance pursuant to the provisions of the company's Shareholders' Rights Plan.

On September 13, 2005, the company declared a 3-for-2 stock split to shareholders of record on September 26, 2005. Accordingly, 3,170,000 additional shares were issued on October 11, 2005. Common stock has been increased by the par value of the shares issued with a corresponding decrease in capital in excess of par value for all periods presented.

Reclassifications

Certain 2006 and 2005 amounts have been reclassified to conform to current year presentation. Such reclassifications had no effect on net income or shareholders' equity.

(3) COMMITMENTS

The company leases office facilities under an operating lease agreement entered into May 1, 2006 which expires April 30, 2011. The lease agreement requires payments of $32,000 in each year through 2010, and $15,000 in 2011. Total rental expense was $75,000 in 2007, $80,000 in 2006, and $79,000 in 2005. The company has no capital leases and no other operating lease commitments.

(4) BENEFIT PLANS

Profit Sharing 401(k) Plan

The company has established a 401(k) plan for the benefit of its employees. Eligible employees may make voluntary contributions not exceeding statutory limitations to the plan. These contributions may be matched by the company, at its discretion. Historically, the company has made matching contributions ranging from 40% to 50% of the employees annual contributions. Matching contributions recorded in fiscal 2007, 2006 and 2005 were $44,000, $37,000, and $39,000, respectively.

Other Company Benefits

The company provides a health and welfare benefit plan to all regular full-time employees. The plan includes health insurance.

(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 fiscal years ended October 31, 2007, 2006, and 2005 are as follows:

	October 31,		
	2007	2006	2005
Net income	**$ 6,091,000**	$ 5,880,000	$ 5,022,000
Other comprehensive income(loss):			
Change in fair value of derivatives	**(454,000)**	1,203,000	182,000
Income tax (expense) benefits	**123,000**	(247,000)	(51,000)
Total comprehensive income	**$ 5,760,000**	$ 6,836,000	$ 5,153,000

(6) INCOME TAXES

The 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.

At October 31, 2007 the company had $828,000 of statutory depletion carry forward for tax return purposes.

The income tax expense recorded in the Consolidated Statements of Operations consists of the following:

	Years Ended October 31,		
	2007	2006	2005
Current	**$ 1,150,000**	$ 473,000	$ 715,000
Deferred	**1,288,000**	1,756,000	1,237,000
Total income tax expense	**$ 2,438,000**	$ 2,229,000	$ 1,952,000

The effective income tax rate differs from the U.S. Federal statutory income tax rate due to the following:

	Years Ended October 31,		
	2007	2006	2005
Federal taxes at statutory rate	**2,994,000**	2,838,000	2,441,000
Graduated rates	**(64,000)**	(62,000)	(72,000)
State income taxes and other	**169,000**	228,000	163,000
Percentage depletion	**(661,000)**	(775,000)	(580,000)
	2,438,000	2,229,000	1,952,000

The principal sources of temporary differences resulting in deferred tax assets and tax liabilities at October 31, 2007 and 2006 are as follows:

	October 31, 2007	2006
Deferred tax assets:		
Gain on property sales	**$ 800,000**	$ 789,000
Total deferred tax assets	**800,000**	789,000
Deferred tax liabilities:		
Intangible drilling, leasehold and other exploration costs capitalized for financial reporting purposes but deducted for tax purposes	**(8,843,000)**	(7,661,000)
State taxes and other	**(1,161,000)**	(1,167,000)
Total deferred tax liabilities	**(10,004,000)**	(8,828,000)
Net deferred tax liability	**$ (9,204,000)**	$ (8,039,000)

(7) EXCLUSIVE LICENSE AGREEMENT OBLIGATION

On September 1, 2000, the company acquired an unrestricted, exclusive license for patented technology. The initial license term was 10 years and includes an option for the company to extend the term to the remaining life of the patents. The licensor will receive a net 8.3% carried interest in any installation of the technology. The license purchase price was $1,115,000, of which $953,000 has been paid. The balance, which is due in two remaining annual increments of $93,750, is recorded at 10% present value. The related assets are being amortized over 10 years on a straight-line basis. If the option to extend the license after the initial 10-year term is exercised, the cost will be $93,750 per year to the expiration of the last patent.

	October 31, 2007 Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:		
Exclusive license agreement	$ 699,000	$ 501,000
Aggregate amortization expense:		
For the year ended October 31, 2007		$ 70,000
Estimated future amortization expense:		
For the year ended October 31, 2008		70,000
For the year ended October 31, 2009		70,000
For the year ended October 31, 2010		58,000
Total		$ 198,000

This amortizable intangible asset is an exclusive license agreement related solely to the company's patented liquid lift system for low pressure gas wells.

The company reviews the value of its intangible assets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets", which requires that it evaluate these assets for impairment whenever events or changes in business circumstances indicate that the carrying amount of the assets may not be fully recoverable or that the useful lives of these assets are no longer appropriate.

At October 31, 2007, this amortizable intangible asset had a net book value of $198,000. The value of this asset is believed to be realizable based on the company's estimation of future cash flows from application of the company's patented liquid lift system. The company's impairment test compares the estimated undiscounted future net cash flows related to this asset with the related net capitalized costs of the asset at the end of each period. If the net capitalized cost exceeds the undiscounted future net cash flows, the cost of the asset is written down to estimated fair value. As of October 31, 2007, the company has not recorded an impairment write-down for this asset. The estimated undiscounted value of future net cash flows is derived from estimates of proved reserve values.

(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 the company's oil and gas properties. The company has classified inventory 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) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

	October 31,		
	2007	2006	2005
Unevaluated properties not being amortized	**$ 7,791,000**	$ 7,060,000	$ 3,452,000
Properties being amortized	**51,691,000**	43,588,000	36,121,000
Accumulated depreciation, depletion and amortization	**(22,108,000)**	(18,556,000)	(15,022,000)
Total capitalized costs	**$ 37,374,000**	$ 32,092,000	$ 24,551,000

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 year incurred, the unevaluated oil and gas property costs (net of transfers to the full cost pool and sales proceeds) excluded from the amortization computation as of October 31, 2007:

Net Costs Incurred During Periods Ended:	Total Unevaluated Properties
October 31, 2007	$ 3,274,000
October 31, 2006	2,629,000
October 31, 2005	1,888,000
	$ 7,791,000

Prospect leasing and acquisition normally requires one to two years and the subsequent evaluation normally requires an additional one to two years.

Acquisition, Exploration and Development Costs Incurred (Net of Sales)

	Years Ended October 31,		
	2007	2006	2005
Property acquisition costs net of divestiture proceeds:			
Proved	**$ 82,000**	$ 102,000	$ 81,000
Unproved	**2,106,000**	1,815,000	2,092,000
Exploration costs	**3,368,000**	6,388,000	834,000
Development costs	**3,252,000**	2,786,000	4,170,000
Total before asset retirement obligation	**$ 8,808,000**	$ 11,091,000	$ 7,177,000
Total including asset retirement obligation	**$ 8,834,000**	$ 11,076,000	$ 7,327,000

Major Customers and Operating Region

The company operates exclusively within the United States. Except for cash investments, all of the company's assets are employed in, and all its revenues are derived from, the oil and gas industry. The company had sales in excess of 10% of total revenues to oil and gas purchasers as follows: Duke Energy 40% in 2007, 39% in 2006 and 40% in 2005.

Oil and Gas Reserve Data (Unaudited)

Independent petroleum engineers estimated proved reserves for the company's properties which represented approximately 64% in 2007, 63% in 2006 and 63% in 2005 of total estimated future net revenues. The remaining reserves were estimated by the company. Reserve definitions and pricing requirements prescribed by the Securities and Exchange Commission were used. The determination of oil and gas reserve quantities involves numerous estimates which are highly complex and interpretive. The estimates are subject to continuing re-evaluation and reserve quantities may change as additional information becomes available. Estimated values of proved reserves were computed by applying prices in effect at October 31 of the indicated year. The average price used was $86.61, $53.69 and $55.59 per barrel for oil and $5.89, $6.32 and $10.26 per Mcf for gas in 2007, 2006 and 2005, respectively. Estimated future costs were calculated assuming continuation of costs and economic conditions at the reporting date.

Total estimated proved reserves and the changes therein are set forth below for the indicated year.

	2007		2006		2005	
	Gas(Mcf)	**Oil(bbls)**	Gas(Mcf)	Oil(bbls)	Gas(Mcf)	Oil(bbls)
Proved reserves:						
Balance, November 1	**16,005,000**	**422,000**	15,516,000	386,000	15,273,000	407,000
Revisions of previous estimates	**(548,000)**	**52,000**	(637,000)	24,000	(889,000)	(6,000)
Extensions and discoveries	**3,442,000**	**168,000**	3,302,000	53,000	2,962,000	22,000
Purchases of reserves in place	**-**	**-**	-	-	-	-
Sales of reserves in place	**-**	**-**	-	-	-	-
Production	**(1,926,000)**	**(51,000)**	(2,176,000)	(41,000)	(1,830,000)	(37,000)
Balance, October 31	**16,973,000**	**591,000**	16,005,000	422,000	15,516,000	386,000
Proved developed reserves:						
Beginning of year	**13,683,000**	**397,000**	13,603,000	381,000	13,993,000	374,000
End of year	**12,890,000**	**458,000**	13,683,000	397,000	13,603,000	381,000

The standardized measure of discounted future net cash flows from reserves is set forth below as of October 31 of the indicated year.

	2007	2006	2005
Future cash inflows	**$ 151,169,000**	$123,889,000	$ 180,726,000
Future production and development costs	**(49,667,000)**	(39,028,000)	(43,848,000)
Future income tax expense	**(24,967,000)**	(20,747,000)	(36,054,000)
Future net cash flows	**76,535,000**	64,114,000	100,824,000
10% discount factor	**(29,734,000)**	(24,363,000)	(41,337,000)
Standardized measure of discounted future net cash flows	**$ 46,801,000**	$ 39,751,000	$ 59,487,000

The principal sources of change in the standardized measure of discounted future net cash flows from reserves are set forth below for the indicated year.

	2007	2006	2005
Balance, November 1	**$ 39,751,000**	$ 59,487,000	$ 32,859,000
Sales of oil and gas produced, net of production costs	**(12,800,000)**	(12,430,000)	(10,384,000)
Net changes in prices and production costs	**3,233,000**	(33,058,000)	29,821,000
Extensions and discoveries, net of future development and production costs	**16,658,000**	12,998,000	15,804,000
Changes in future development costs	**(12,000)**	(536,000)	(1,692,000)
Previously estimated development costs incurred during the period	**932,000**	1,299,000	2,248,000
Revisions of previous quantity estimates, timing, and other	**(2,355,000)**	(3,396,000)	(2,962,000)
Purchases of reserves in place	**-**	-	-
Sales of reserves in place	**-**	-	-
Accretion of discount	**3,975,000**	5,949,000	3,286,000
Net change in income taxes	**(2,581,000)**	9,438,000	(9,493,000)
Balance, October 31	**$ 46,801,000**	$ 39,751,000	$ 59,487,000

(10) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following is a tabulation of the company's unaudited quarterly operating results for fiscal 2005, 2006 and 2007:

	Total Revenue	Income Before Income Taxes	Net Income	Basic Net Income Per Share	Diluted Net Income Per Share
Fiscal 2005:					
First Quarter	$ 2,447,000	$ 1,189,000	$ 856,000	$ 0.10	$ 0.09
Second Quarter	3,038,000	1,565,000	1,127,000	0.12	0.12
Third Quarter	3,501,000	1,892,000	1,362,000	0.15	0.15
Fourth Quarter	4,303,000	2,328,000	1,677,000	0.18	0.18
	$ 13,289,000	$ 6,974,000	$ 5,022,000	$ 0.55	$ 0.54
Fiscal 2006:					
First Quarter	$ 4,365,000	$ 2,354,000	$ 1,695,000	$ 0.19	$ 0.18
Second Quarter	3,921,000	1,963,000	1,392,000	0.15	0.15
Third Quarter	3,969,000	1,799,000	1,286,000	0.14	0.14
Fourth Quarter	4,236,000	1,993,000	1,507,000	0.16	0.15
	$ 16,491,000	$ 8,109,000	$ 5,880,000	$ 0.64	$ 0.62
Fiscal 2007:					
First Quarter	$ 4,055,000	$ 1,900,000	$ 1,364,000	$ 0.15	$ 0.15
Second Quarter	4,891,000	2,780,000	1,982,000	0.21	0.21
Third Quarter	4,047,000	1,945,000	1,391,000	0.15	0.15
Fourth Quarter	4,000,000	1,904,000	1,354,000	0.15	0.14
	$ 16,993,000	$ 8,529,000	$ 6,091,000	$ 0.66	$ 0.65

Report Of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Credo Petroleum Corporation

We have audited the consolidated balance sheets of Credo Petroleum Corporation and subsidiaries as of October 31, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended October 31, 2007. Our audits also included the financial statement schedules of Credo Petroleum Corporation listed in Item 15(a). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Credo Petroleum Corporation and subsidiaries as of October 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Credo Petroleum Corporation's and subsidiaries' internal control over financial reporting as of October 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Our report dated January 14, 2008 expressed an opinion that Credo Petroleum Corporation had not maintained effective internal control over financial reporting as of October 31, 2007, based on COSO.

/s/ HEIN & ASSOCIATES LLP
Denver, Colorado
January 14, 2008

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Report on Internal Control Over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting by using the criteria established by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework*. Based on our evaluation under the framework in

Internal Control–Integrated Framework, our management identified a material weakness in the company's internal controls over financial reporting. A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected by the company's internal control over financial reporting.

This material weakness did not result in a material misstatement of the company's October 31, 2007 financial statements and did not require any changes to those financial statements. Nevertheless, management concluded that the possibility of a material misstatement due to the significant internal control deficiency was more than remote resulting in it being a material weakness. As a result, management concluded that the company's disclosure controls and procedures were not operating effectively as of October 31, 2007, due to the material weakness described below.

> The company does not have the technical resources to review highly complex and non-recurring transactions.

Management intends to address this material weakness by providing additional training for its senior accounting staff in certain highly technical and complex accounting areas involving new rules and pronouncements and new interpretations of rules and pronouncements, and may retain experts to advise it regarding these areas.

Limitations of the effectiveness of internal control. Because of its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Report Of Independent Registered Public Accounting Firm

Board of Directors CREDO Petroleum Corporation and Subsidiaries
Denver, Colorado

We have audited Credo Petroleum Corporation's internal control over financial reporting as of October 31, 2007, based on criteria established in *Internal Control–Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Credo Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment. The Company did not have a sufficient complement of personnel with appropriate training and experience to evaluate highly complex and/or unusual transactions under generally accepted accounting principles and Securities and Exchange Commission's accounting interpretations. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the October 31, 2007 financial statements, and this report does not affect our report dated January 14, 2008 on those financial statements.

In our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Credo Petroleum Corporation has not maintained effective internal control over financial reporting as of October 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated Balance Sheets and the related consolidated statements of operations, stockholders' equity, and cash flows and expressed an unqualified opinion.

/s/ HEIN & ASSOCIATES LLP
Denver, Colorado
January 14, 2008

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS, RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to instruction G (3) to Form 10-K, Items 10, 11, 12, 13 and 14 are omitted because the company will file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such items will be included in the Proxy Statement to be so filed for the company's annual meeting of shareholders to be held on or about March 20, 2008 and is hereby incorporated by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements:
- Consolidated Balance Sheets - October 31, 2007 and 2006
- Consolidated Statements of Operations - Three Years ended October 31, 2007
- Consolidated Statements of Shareholders' Equity - Three Years ended October 31, 2007
- Consolidated Statements of Cash Flows - Three Years ended October 31, 2007
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm

(2) Financial Statement Schedules:

Schedules are omitted because of the absence of the conditions under which they are required or because the information is included in the financial statements or notes to the financial statements.

(b) Exhibits. The following exhibits are filed with or incorporated by reference into this report on Form 10-K.

3(a)(i) & 4(a)	Articles of Incorporation of CREDO Petroleum Corporation (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(ii)	Articles of Amendment of Articles of Incorporation, dated March 9, 1982 (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(iii)	Articles of Amendment of Articles of Incorporation, dated October 28, 1982 (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(iv)	Articles of Amendment of Articles of Incorporation dated April 18, 1984 (incorporated by reference to Form 10-K dated October 31, 1984).
3(a)(v)	Articles of Amendment of Articles of Incorporation dated April 18, 1984 (incorporated by reference to Form 10-K dated October 31, 1984).
3(a)(vi)	Articles of Amendment of Articles of Incorporation dated April 2, 1985 (incorporated by reference to Form 10-K dated October 31, 1985).
3(a)(vii)	Articles of Amendment of Articles of Incorporation dated March 25, 1986 (incorporated by reference to Form 10-K dated October 31, 1986).
3(a)(viii)	Articles of Amendment of Articles of Incorporation dated March 24, 1988 (incorporated by reference to Form 10-K dated October 31, 1989).
3(a)(ix)	Articles of Amendment to Articles of Incorporation dated May 11, 1990.
3(b)(i)	By-Laws of CREDO Petroleum Corporation, as amended October 30, 1986 (incorporated by reference to Form 10-K dated October 31, 1986).
3(b)(ii)	Amendment to Article X of CREDO Petroleum Corporation's By-Laws dated March 24, 1988 (incorporated by reference to the company's definitive proxy dated February 5, 1988).
4(i)	Shareholders' Rights Plan, dated April 11, 1989.
4(ii)	Amendment to Shareholders' Rights Plan, dated February 24, 1999 (incorporated into Part II of the company's Form 10-QSB dated January 31, 1999).
10(a)	CREDO Petroleum Corporation Non-qualified Stock Option Plan, dated January 13, 1981 (incorporated by reference to Amendment No. 1 to Form S-1 dated February 2, 1981).
10(b)	CREDO Petroleum Corporation Incentive Stock Option Plan, dated October 2, 1981 (incorporated by reference to the company's definitive proxy statement, dated January 22, 1982).
10(c)	Model of Director and Officer Indemnification Agreement provided for by Article X of CREDO Petroleum Corporation's By-Laws (incorporated by reference to Form 10-K dated October 31, 1987).
10(d)	CPC Exclusive License Agreement, dated September 1, 2000 (incorporated by reference to Form 10-KSB dated October 31, 2000).
10(e)	CREDO Petroleum Corporation 1997 Stock Option Plan, as amended and restated effective October 25, 2001 (incorporated by reference to Form 10-KSB dated October 31, 2001).
10(f)	CREDO Petroleum Corporation 2007 Stock Option Plan (incorporated by reference to the company's definitive proxy statement filed with the SEC on February 20, 2007).
14.1	Code of Business Conduct and Ethics (incorporated by reference to Form 10-KSB dated October 31, 2004).
21	CREDO Petroleum Corporation (a Colorado corporation) and its subsidiaries SECO Energy Corporation (a Nevada corporation) and United Oil Corporation (an Oklahoma corporation) are located at 1801 Broadway, Suite 900, Denver, CO 80202-3837.
23.1 *	Consent of Independent Registered Public Accounting Firm dated January 14, 2008
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).

* Filed with this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 in the City of Denver, State of Colorado on January 14, 2008.

CREDO PETROLEUM CORPORATION
(Registrant)

By: /s/ James T. Huffman
James T. Huffman,
Chairman of the Board of Directors, President and Chief Executive Officer

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
January 14, 2008	/s/ James T. Huffman James T. Huffman	Chairman of the Board of Directors, President, Treasurer and Chief Executive Officer (Principal Executive Officer)
January 14, 2008	/s/ David E. Dennis David E. Dennis	Chief Financial Officer (Principal Financial and Accounting Officer)
January 14, 2008	/s/ Clarence H. Brown Clarence H. Brown	Director
January 14, 2008	/s/ Oakley Hall Oakley Hall	Director
January 14, 2008	/s/ William F. Skewes William F. Skewes	Director
January 14, 2008	/s/ Richard B. Stevens Richard B. Stevens	Director

Board of Directors and Corporate Information

Directors

Clarence H. Brown
Petroleum Engineer and
Independent Businessman
Westminster, Colorado

Oakley Hall
Retired PricewaterhouseCoopers Partner
and Independent Businessman
Kingwood, Texas

James T. Huffman
Chairman, Chief Executive Officer
and President of the Company
Denver, Colorado

William F. Skewes
Attorney
Denver, Colorado

Richard B. Stevens
Oil Operator and
Independent Businessman
Phoenix, Arizona

Executive Officers

James T. Huffman
Chairman, Chief Executive Officer
and President

David E. Dennis
Chief Financial Officer
and Secretary

Corporate Counsel

Davis Graham & Stubbs LLP
Denver, Colorado

Hall, Estill, Hardwick, Gable,
Gordon & Nelson, P.C.
Oklahoma City, Oklahoma

Executive Offices

1801 Broadway, Suite 900
Denver, Colorado 80202
(303) 297-2200
Website: www.credopetroleum.com

Subsidiaries

SECO Energy Corporation
1801 Broadway, Suite 900
Denver, Colorado 80202

United Oil Corporation
1801 Broadway, Suite 900
Denver, Colorado 80202

Independent Registered Public Accounting Firm

Hein & Associates LLP
Denver, Colorado

Registrar and Transfer Agent

Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden, Colorado 80401

Stock Exchange and Trading Range

NASDAQ Global Market
NASDAQ Symbol: CRED

Market quotations shown below were reported by the National Association of Securities Dealers, Inc. and represent prices between dealers excluding retail mark-up or commissions.

	2007		2006	
Fiscal Quarter Ended	High	Low	High	Low
Jan. 31	$13.27	$11.55	$30.46	$17.16
April 30	16.00	11.58	29.97	20.46
July 31	14.60	11.78	25.40	16.85
Oct. 31	11.92	9.52	22.02	12.86

At January 8, 2008, the company had 2,496 share-holders of record. The company has never paid a dividend and does not expect to pay any dividends in the foreseeable future. Earnings are reinvested in business activities.

roleum Corporation
roadway, Suite 900
Denver, CO 80202
(303) 297-2200
www.credopetroleum.com

END