CREDO PETROLEUM CORP
Form 10-K
January 26, 2007

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

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

For The Fiscal Year Ended October 31, 2006

or

o **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

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: o Yes þ 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: o Yes þ 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. þ Yes o 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. þ

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of April 30, 2006, the end of the registrant s most recently completed second quarter was $171,035,000.
As of January 8, 2007, the registrant had 9,261,000 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 22, 2007 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 From Reserves as shown in Note 8 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;
- expectations regarding oil and natural gas prices and demand;
- existing fields, wells and prospects;
- diversification of exploration;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- the company s business strategy;
- production of oil and natural gas;

matters related to the Calliope Gas Recovery System, 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 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 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 2006, the company continued implementation of new projects commenced in 2005 which 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 68,000 gross acres. The company will continue generating prospects and drilling on this acreage concentrating on medium depth properties generally ranging from 7,000 to 9,000 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.

Commencing in 2005, the company 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 15,500 feet. The north-central Kansas projects are 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 clearly different 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 which 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, 2006, Calliope has been installed on 24 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.

Commencing in 2005, the company significantly expanded its Calliope operations by moving into Texas and Louisiana and by entering into discussions with other companies regarding the formation of joint venture arrangements that utilize Calliope. In addition, higher gas prices have facilitated a new Calliope project to drill wells into low-pressure reservoirs continuing substantial stranded gas reserves. Calliope will then be used to recover those reserves. This is expected to enhance the company s control over monetizing Calliope s value while providing the opportunity to optimize Calliope s performance and broaden the range of reservoirs for Calliope applications. 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 111 wells pursuant to standard industry operating agreements. The company owns interests in approximately 1,426 wells of which approximately 1,159 wells represent small overriding royalty interests.

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 $78.00 per barrel during 2006.

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.

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 (8) 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 2007. 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 19 for further information.

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.

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, 2006, approximately 13% 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 53 properties which represent 24% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual wells on which Calliope is installed comprise 23% of these significant properties and 28% of the discounted reserve value of such properties. New wells comprise 9% of these significant properties and 20% 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 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.

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 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 68,000 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 10,000 feet. Since 2001, the company has participated in drilling approximately 75 wells on such prospects with interests ranging up to 83%. Of those wells, 55 were completed as producers and 20 were dry holes. Several of the wells are exceptional for the area, and 16 of the wells are included in the company s Significant Properties (see definition below). The company believes that it will drill more good wells in the area.

The company owns the exclusive right to the Calliope Gas Recovery System. The company believes it has proven that Calliope will add 0.5 to 2.0 Bcf of proved gas reserves to many dead and uneconomic wells. The company also 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 24 wells located in Oklahoma, Texas and Louisiana, which range in depth from 6,500 to 18,400 feet. All of the wells were either dead or uneconomic at the time Calliope was installed. Twelve Calliope wells are included in the company s Significant Properties. The company recently expanded its Calliope operations into Texas and Louisiana.

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 53 properties (Significant Properties). Some of the Significant Properties are individual wells and others are multi-well properties. At year-end, Significant Properties represent 24% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual Calliope wells comprise 23% of the Significant Properties and represent 28% of the discounted reserve value of such properties. New wells comprise 9% of the Significant Properties and represent 20% 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 63% in 2006, 63% in 2005 and 61% in 2004 of the total estimated future value of estimated reserves. Remaining reserves were estimated by the company in all years. At October 31, 2006, natural gas represented 86% and crude oil represented 14% 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 (8) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $53.69, $55.59 and $50.43 per barrel of oil and $6.32, $10.26 and $5.84 per Mcf of gas as of October 31, 2006, 2005 and 2004, respectively. Amounts do not include estimates of future Federal and state income taxes.

Year	Oil (bbls)*	Gas (Mcf)*	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2006	**422,000**	**16,005,000**	**$ 84,861,000**	**$ 52,328,000**
2005	386,000	15,516,000	$ 136,878,000	$ 81,209,000
2004	407,000	15,273,000	$ 77,612,000	$ 44,551,000

* The percentage of total reserves classified as proved developed was approximately 87% in 2006, 89% in 2005, and 93% in 2004.

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 From Reserves as shown in Note 8 to the company s Consolidated Financial Statements.

	Year Ended October 31,		
	2006	2005	2004
Estimated future net revenues discounted at 10%	$ 52,328,000	$ 81,209,000	$ 44,551,000
Future income tax expense	(20,747,000)	(36,054,000)	(19,965,000)
Effect of the 10% discount factor on future income tax expense	8,170,000	14,332,000	8,273,000
Standardized measure of discounted future net cash flows from reserves	$ 39,751,000	$ 59,487,000	$ 32,859,000

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.

	2006		2005		2004	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**2,176,000**	**$ 6.11**(1)	1,830,000	$ 6.16(2)	1,710,000	$ 4.60(3)
Oil (bbls)	**41,000**	**$61.14**	37,000	$50.90	41,000	$36.57

(1) Includes $0.12 Mcf hedging loss.

(2) Includes $0.39 Mcf hedging loss.

(3) Includes $0.42 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 $1.40, $1.35 and $1.06 per Mcfe in 2006, 2005 and 2004, respectively.

Productive Wells and Developed Acreage

Developed acreage at October 31, 2006 totaled 28,000 net and 118,000 gross acres. At October 31, 2006, the company owned working interests in 77.42 net (266 gross) wells consisting of 16.03 net (43 gross) oil wells and 61.39 net (223 gross) natural gas wells. In addition, the company owned royalty and production payment interests in approximately 1,159 wells, primarily coal bed methane located in Wyoming. In 2006, the company sold 2.21 net (3 gross) wells. In the same period, the company drilled and acquired interests in 4.47 net (12 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	Net	Working Interest Acreage Gross	Net
2007	1,900		21,200	7,600
2008			23,100	6,800
2009			6,000	2,800
2010	3,300	100	5,000	1,000
2011			100	
Thereafter	1,800	500	300	200
Held-By-Production	152,100	7,900	15,500	3,200
Total	159,100	8,500	71,200	21,600

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 October 31,	Total Gross Wells	Exploratory Oil	Exploratory Gas	Exploratory Dry	Development Oil	Development Gas	Development Dry
2006	**27**	**1**	**9**	**13**	**1**	**3**	
2005	26		10	2		14	
2004	25	1	3	4		14	3
1978-2003	255	12	113	81	15	29	5
Total	333	14	135	100	16	60	8

Net Wells

Year Ended October 31,	Total Net Wells	Exploratory Oil	Exploratory Gas	Exploratory Dry	Development Oil	Development Gas	Development Dry
2006	**10.421**	**0.300**	**3.184**	**5.029**	**0.306**	**1.602**	
2005	4.683		3.075	0.208		1.400	
2004	6.899	.306	1.381	2.074		1.980	1.158
1978-2003	43.833	1.557	18.626	13.180	4.350	4.135	1.985
Total	65.836	2.163	26.266	20.491	4.656	9.117	3.143

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

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that this space is adequate for its current needs. The company s current lease expires in April 2011.
As of October 31, 2006, 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 material 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 2006.

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 National Association of Securities Dealers Automated Quotation System under the 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 and may not necessarily represent actual transactions.

	2006		2005	
Quarter Ended	**High**	**Low**	High	Low
January 31	**$ 30.46**	**$ 17.16**	$ 9.93	$ 8.21
April 30	**$ 29.97**	**$ 20.46**	$ 11.29	$ 9.00
July 31	**$ 25.40**	**$ 16.85**	$ 11.99	$ 9.15
October 31	**$ 22.02**	**$ 12.86**	$ 18.80	$ 11.87

At January 8, 2007, the company had 2,620 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.

The company did not repurchase any shares of its common stock during the fiscal year ended October 31, 2006.

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, 2006 were derived from the audited financial statements and the accompanying notes to those financial statements.

	Years Ended October 31,				
	2006	2005	2004	2003	2002
Audited Financial Information					
Statement of Operations Data:					
Oil and gas sales	**$15,837,000**	$ 13,143,000	$ 9,367,000	$ 7,494,000	$ 4,698,000
Investment and other income	**654,000**	146,000	343,000	461,000	172,000
Oil and gas production expense	**3,407,000**	2,759,000	2,075,000	1,608,000	1,291,000
Depreciation, depletion and amortization	**3,642,000**	2,402,000	1,747,000	1,333,000	1,202,000
General and administrative	**1,291,000**	1,117,000	1,171,000	1,315,000	713,000
Interest expense	**42,000**	37,000	39,000	46,000	49,000
Income before income taxes and cumulative effect of change in accounting principle	**8,109,000**	6,974,000	4,678,000	3,653,000	1,615,000
Net income	**5,880,000**	5,022,000	3,368,000	2,702,000	1,179,000
Net income per share[(1)]:					
Basic	**$ 0.64**	$ 0.55	$ 0.37	$ 0.30	$ 0.13
Diluted	**$ 0.62**	$ 0.54	$ 0.36	$ 0.30	$ 0.13
Weighted-average shares outstanding[(1)]:					
Basic	**9,207,000**	9,080,000	9,036,000	8,869,000	8,761,000
Diluted	**9,482,000**	9,367,000	9,282,000	9,042,000	8,952,000
Balance Sheet Data:					
Working capital	**10,073,000**	7,697,000	5,611,000	6,577,000	6,630,000
Total assets	**47,759,000**	37,844,000	30,976,000	23,572,000	18,811,000
Long-term obligations:					
Deferred income taxes-net	**8,039,000**	5,978,000	4,605,000	3,192,000	2,276,000
Asset retirement obligation	**954,000**	929,000	748,000	238,000	
Exclusive license agreement obligation	**163,000**	233,000	297,000	355,000	408,000
Stockholders equity	**34,767,000**	26,947,000	20,920,000	17,635,000	14,307,000

Unaudited Operating Data

Production Volumes:

Gas (Mcf)	**2,176,000**	1,830,000	1,710,000	1,449,000	1,298,000
Oil (Bbls)	**41,000**	37,000	41,000	35,000	37,000
Mcfe	**2,422,000**	2,050,000	1,960,000	1,660,000	1,520,000
Average sales price before hedging:					
Per Mcf	**$ 6.23**	$ 6.55	$ 5.02	$ 4.57	$ 2.61
Per Bbls	**$ 61.14**	$ 50.90	$ 36.57	$ 27.68	$ 22.01
Average sales price after hedging:					
Per Mcf	**$ 6.11**	$ 6.16	$ 4.60	$ 4.50	$ 3.00
Per Bbls	**$ 61.14**	$ 50.90	$ 36.57	$ 27.68	$ 22.01
Reserves:					
Gas (Mcf)	**16,005,000**	15,516,000	15,273,000	13,786,000	9,415,000
Oil (Bbls)	**422,000**	386,000	407,000	385,000	337,000
Mcfe	**18,537,000**	17,835,000	17,717,000	16,097,000	11,435,000
Estimated future net revenues	**$84,861,000**	$136,878,000	$77,612,000	$45,165,000	$29,774,000
Estimated future net revenues discounted at 10%	**$52,328,000**	$ 81,209,000	$44,551,000	$28,024,000	$18,035,000

(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, 2006, working capital was $10,073,000, compared to $7,697,000 at October 31, 2005. For the year ended October 31, 2006, net cash provided by operating activities increased 47% to $12,973,000 compared to net cash provided by operating activities of $8,821,000 for the same period in 2005. This increase is primarily the result of increases in net income and other non-cash items (DD&A, deferred income taxes, compensation expense related to stock option grants, and other) of $2,746,000; a net increase of $129,000 in short term investments in 2006 versus a net decrease in short term investments of $876,000 in 2005 which resulted in a decrease of $1,005,000 between the two periods; a net increase in cash as a result of changes in accrued oil and gas sales, trade receivables and other current assets of $1,683,000; and a net increase in cash as a result of changes in accounts payable and income taxes payable of $728,000. For the year ended October 31, 2006 and 2005, net cash used in investing activities was $11,096,000 and $7,667,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $11,746,000 and $6,938,000, respectively. Financing activities primarily included proceeds from exercise of stock options of $835,000 and $335,000 in 2006 and 2005, respectively. The average return on the company s investments for the year ended October 31, 2006 and 2005 was 8.4% and 2.8%, respectively. At October 31, 2006, approximately 40% 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, 2006, 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, 2006, 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	$ 281,000	$ 94,000	$ 187,000	$	$
Operating lease obligations	142,000	32,000	63,000	47,000	
Total	$ 423,000	$ 126,000	$ 250,000	$ 47,000	$

The company s earnings before interest, taxes, depreciation, depletion and amortization, (EBITDA) increased 25% to $11,793,000 for the year ended October 31, 2006 from $9,413,000 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,		
	2006	2005	2004
RECONCILIATION OF EBITDA:			
Net Income	**$ 5,880,000**	$ 5,022,000	$ 3,368,000
Add Back:			
Interest Expense	**42,000**	37,000	39,000
Income Tax Expense	**2,229,000**	1,952,000	1,310,000
Depreciation, Depletion and Amortization Expense	**3,642,000**	2,402,000	1,747,000
EBITDA	**$ 11,793,000**	$ 9,413,000	$ 6,464,000

Off-Balance Sheet Financing

The company has no off-balance sheet financing arrangements at October 31, 2006.

Product Prices and Production

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

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

The company recognizes all derivatives (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 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.

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had after tax hedging losses of $191,000 in fiscal 2006, $518,000 in fiscal 2005 and $516,000 in 2004. Any hedge ineffectiveness, which was not material for the three years ended October 31, 2006, is immediately recognized in gas sales.

Hedges include contracts indexed to the NYMEX and 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 2006) and unrealized (December 2006 through July 2007) gains and losses on hedge contracts at October 31, 2006 totaled $897,000 and were included in Other Comprehensive Income . These contracts covered 950 MMBtus at NYMEX basis prices ranging from $6.25 to $9.98.

As of December 31, 2006, hedges covering the months of November 2006 through January of 2007 had been closed at expiration resulting in a gain of $438,000. Such hedges covered 480 MMBtus at NYMEX basis prices ranging from $6.25 to $11.44. Open hedge positions as of December 31, 2006, are set forth below.

Commodity	**Volume**	**Average Price NYMEX Basis**	**Period Covered**
Natural Gas Short	150 MMbtu	9.35	February 2007
Natural Gas Short	140 MMbtu	9.30	March 2007
Natural Gas Short	140 MMbtu	8.17	April 2007
Natural Gas Short	130 MMbtu	7.75	May 2007
Natural Gas Short	130 MMbtu	7.78	June 2007
Natural Gas Short	120 MMbtu	7.81	July 2007

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 $4,500,000 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 unfunded debt in excess of $500,000. It expires on October 31, 2007.

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.

	2006		2005		2004	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**2,176,000**	**$ 6.11**(1)	1,830,000	$ 6.16(2)	1,710,000	$4.600(3)
% change	**+19%**	**-1%**	+7%	+34%	+18%	+2%
Oil (bbls)	**41,000**	**$61.14**	37,000	$50.90	41,000	$36.57
% change	**+11%**	**+20%**	-10%	+39%	+18%	+32%

(1) Includes $0.l2 Mcf hedging loss.

(2) Includes $0.39 Mcf hedging loss.

(3) Includes $0.42 Mcf hedging loss.

Most oil and condensate volumes are associated with natural gas production and, therefore, vary from well to well depending on the volume and richness of the natural gas produced. Significant Properties (see definition on page 11) contributed 41% of 2006 production on a gas-equivalent basis. Increases in natural gas volumes resulted primarily from successful drilling in Oklahoma.

Oil and Gas Activities

Capital Spending. Capital spending in 2006 totaled $11,076,000.

Operations

During fiscal 2006, the company s operations were focused on its two core projects natural gas drilling and application of its patented Calliope Gas Recovery System.

As discussed below, the company has expanded into South Texas through an exploration program using 3-D seismic to define the Vicksburg, Frio, Queen City and Wilcox prospects in Hidalgo and Jim Hogg counties. The company has also expanded into north-central Kansas through an exploration program using 3-D seismic to define Lansing-Kansas City oil prospects along the Central Kansas Uplift.

Also as discussed below, the company has expanded its Calliope operations into Texas and Louisiana. The company believes these are fertile areas for Calliope and will continue to expand as opportunities allow. During 2007, the company plans to commence drilling operations on a new project to drill wells into existing reservoirs for the specific purpose of using Calliope to recover stranded gas.

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 2007, 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 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.

Drilling Activities.

Northern Anadarko Basin The company drills primarily on its significant inventory of acreage (approximately 68,000 gross acres) located along the northern portion of the Anadarko Basin where it has drilled approximately 75 wells. The wells 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.

Subsequent to fiscal year-end, the company participated in a 2,500 gross acre prospect located in the Texas Panhandle. An 11,200-foot well was drilled in December that encountered over-pressured Upper Morrow sands. Production casing has been set, and the well is awaiting completion for pipeline sales. The well is classified as a tight hole , meaning that information is not being released for proprietary business reasons. The company owns a 25% working interest.

For the year ended October 31, 2006, the company drilled 16 wells on its Northern Anadarko Basin acreage of which seven were completed at producers. However, drilling is not restricted to the Northern Anadarko Basin. The company is generating prospects elsewhere in the Oklahoma Panhandle, north-central Oklahoma, north-central Kansas, and South Texas and East Texas.

During fiscal 2006, five (5) wells were drilled on the company s 5,760 gross acre Glacier Prospect located in Harper and Woodward Counties, Oklahoma. Two of the wells are producers, two are dry holes, and one well is currently being tested and appears to be a marginal producer. The most important of these wells are the Garnet State and Scarlet State. Both wells encountered excellent Morrow sands at about 7,500 feet, and are producing at high rates for the area. The two wells initially produced at a combined rate of almost 10.0 MMcfe (million cubic of gas equivalent) per day. Previously, the company drilled two other high rate wells on the Glacier prospect, both of which had limited reservoir extent but proved the presence of high quality sands on the prospect. The company owns a 57% working interest in the Garnet State and a 55% interest in the Scarlet State, and is the operator of both wells and the prospect.

Drilling is also continuing on the company s 2,560 gross acre Buffalo Creek Prospect. During 2006 the company completed the 6,900-foot Lauer #1-21 well as the third oil well on the prospect at initial rates over 100 BO (barrels of oil) per day. A 3-D seismic program is currently being conducted to identify additional drilling locations. The company owns a 31% working interest and is the operator.

A second well was drilled on the company s 1,280 gross acre Saddle Prospect and was completed in the Morrow formation producing about 800 Mcf per day. Additional wells are scheduled for the prospect. The company owns a 49% working interest and is the operator.

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

South Texas Last year, the company commenced a new exploration project in South Texas. The project is 3-D seismic driven and focuses on the Vicksburg, Frio, Queen City and Wilcox sands in Hidalgo and Jim Hogg Counties ranging in depth from 7,500 to 17,000 feet. Both the cost and the potential of this project far exceed anything the company had experienced before.

In return for a 75% interest before investment payout (calculated on a prospect by prospect basis) and 37.5% interest after investment payout, the company initially committed $1,500,000 for prospect generation and leasing costs. The commitment has been fully funded and all future project funding is at the company s discretion. The company has the option to participate in drilling each prospect for all, or a portion, of its interest. If the company does not participate for its full interest, the remaining portion will be sold to industry participants on a promoted basis.

The exploration team has generated a significant number of high quality 3-D seismic drilling prospects, and will generate more prospects in the future. Leasing is complete on six prospects, one of which has been drilled. Fully leased prospects include the 800 gross acre Esparza Prospect which targets Marks sands at approximately 12,500 feet, the 2,300 gross acre Sam Houston Prospect which targets Frio sands at approximately 10,500 feet, the 1,200 gross acre West Mestena Prospect which targets Queen City sands at approximately 10,500 feet, the 1,120 gross acre Millennium Prospect which targets Wilcox sands at approximately 15,000, and the 600 gross acre Vela Prospect which targets Frio sands at approximately 7,500 feet.

The company participated for its full 37.5% interest in the first project well which was drilled on the 1,700 gross acre Robertson Prospect in Hidalgo County. Production casing has been set on the 10,500-foot well, and Upper Frio sands have been tested at rates of approximately 1.0 MMcfe per day. However, pressure data indicates that the reservoir may be limited in size. An additional up-hole sand appears on logs to be productive and may be evaluated before a final commercial production decision is made. The 8/8ths cost of the well is expected to range between $3,500,000 and $4,000,000.

In response to drilling costs which have almost doubled since the project began, the company recently elected to reduce its exposure to drilling participation in the next four prospects by selling all, or a significant portion, of its 37.5% interest to industry drilling participants. The company expects to recover its investment in each prospect and retain a promoted interest in exploratory wells with the option to participate in development drilling. Because the project has significant potential to increase production and reserves, the company has reserved the option to participate for its full 37.5% interest in all other prospects. This strategy will reduce the company s South Texas exploration risk and improve its staying power.

North-Central Kansas During 2005 and 2006, the company diversified its exploration by acquiring interests in three different drilling projects encompassing about 30,000 gross acres located on the Central Kansas Uplift. The acreage is located in a prolific producing area of the Central Kansas Uplift where 3-D seismic has recently proven to be an effective exploration tool. The project provides diversification to the company s drilling program, both geographically and scientifically, through the use of 3-D seismic. It also exclusively targets oil reserves which will help bring better product balance to the company s reserve base.

The company owns interests in the projects ranging from 12.5% to 100%. Drilling targets the Lansing-Kansas City formation at 4,000 feet. Completed costs for individual wells are averaging approximately $300,000.

The largest of the three drilling projects is approximately 21,000 gross acres located in Graham and Sheridan Counties, Kansas. The company owns a 30% interest and committed to shoot seismic and participate in drilling five test wells. The commitment has been fully funded and all future project funding is at the company s discretion. Approximately 28 square miles of 3-D seismic have been shot and evaluated, and six exploratory wells have been drilled, of which one well is an excellent producer and five wells are dry holes. The new producer is making 115 BO per day after two months of production. It is located on a prospect containing approximately 1,000 gross acres. Additional development drilling is scheduled for the prospect.

The project is in an early stage and the learning curve is steep. Seismic data is currently being reprocessed and re-evaluated to incorporate data obtained from drilling the initial wells. The company believes drilling results will improve as it gains additional experience in the area. Drilling is expected on approximately 30 prospects.

Calliope Drilling Project See discussion under Calliope Gas Recovery Technology below.

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

Calliope Gas Recovery Technology.

The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. There are currently three U.S. patents and one Canadian patent related to the technology. Two additional patents that mirror the U.S. patents have been applied for in Canada.

Calliope can achieve substantially lower flowing bottom-hole pressure than conventional 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.

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

Calliope Drilling Project During 2006, the company entered into a 50/50 joint venture with Redman Energy Holdings II, L.P. to drill wells for the purpose of using its patented Calliope Gas Recovery System to recover stranded gas reserves. Redman Energy Holdings is an affiliate of Redman Energy Corporation, a privately-held, Houston-based exploration and production company. Redman is affiliated with Natural Gas Partners, a highly respected industry funding source, and brings a wealth of knowledge and a solid operating foundation in the project area. Drilling will concentrate on previously mature, prolific fields containing significant stranded gas.

In its initial phases, the joint venture plans to invest up to $35,000,000 to acquire leases, drill new wells, and install Calliope principally in South and East Texas. Drilling will target large gas fields that were abandoned when natural gas prices were considerably lower than today, and when technologies to remove fluids from wellbores were much less effective than Calliope. The company presently expects to fund its 50% share of the joint venture from existing cash and future cash flow.

Access to fields and drilling locations are generally available through leasing or acquiring interests in old fields. The company believes this project is a target-rich opportunity for the company to take control of expanding its Calliope operations. Wells are expected to range in depth from 8,000 to 13,000 feet. Reserves are projected to range from 1.0 to 3.0 Bcfe (billion cubic feet of gas equivalent) per well, with beginning production rates ranging from 500 to 1,500 Mcf per day. Average drilling economics are expected to include payouts of approximately two years.

Several prospects are currently owned by Redman and several are in various stages of leasing. In addition, Redman has a committed rig that will be available for the project. Drilling is expected to commence during the second quarter of fiscal 2007.

Several of the old fields currently owned by Redman contain very significant stranded gas reserves due to their large reservoir volume and high remaining pressure. The company believes that Calliope will recover billions of cubic feet of gas from these fields by pulling-down reservoir pressure to previously unachievable levels.

This drilling project will be the company s first opportunity to use Calliope to recover stranded reserves from an entire field. The company believes that drilling new wells for Calliope will provide a repeatable opportunity to lease large areas for systematic re-development. In addition, the company intends to install optimum casing and tubular sizes to substantially improve reserves and production compared to installing Calliope on existing wells where undersized tubulars often impede Calliope s performance.

Although there are always risks associated with drilling, the company considers this to be low risk, development type drilling because it involves areas known to be productive. The company believes that drilling wells into under-pressured reservoirs without damaging the reservoir with drilling fluids is key to the success of the project. If that can be done successfully, the company believes that Calliope can be used to recover stranded gas reserves that can estimated with a high degree of confidence.

Purchasing Calliope Candidate Wells Calliope systems are currently installed on 18 wells owned and operated by the company. The wells are located in Oklahoma, Texas and Louisiana, and range in depth from 6,500 to 18,400 feet. They represent the most rigorous applications for Calliope because the wells were either totally dead or uneconomic at the time Calliope was installed. In addition, prior to the time Calliope was installed, many of the reservoirs were damaged by the parting shots of previous operators. Initial Calliope production rates range up to 650 Mcfd (thousand cubic feet of gas per day) and average per well Calliope reserves for non-prototype wells are estimated to be 1.10 Bcf. One of the company s early Calliope installations, the J.C. Carroll well, has now produced almost a billion cubic feet of gas using Calliope.

Calliope operations have recently been expanded into Texas and Louisiana with two installations in southwest Texas and one in Louisiana. 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 Calliope.

In general, higher 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.

In central Louisiana, the company recently installed Calliope on a 13,800-foot well. Calliope immediately restored the well to economic production making about 350 Mcfe per day. In mid-2006, a Calliope system was installed on the 18,000-foot Wallace well located in Beckham County, Oklahoma. The well was dead after having a severe casing leak that dumped an indeterminable amount of corrosive water on the productive formation. Due to the well s high reserve potential, Calliope is being used to remove the water in an attempt to restore production. To date, only minor amounts of gas are being produced, indicating that the casing leak may have damaged the reservoir beyond repair.

A Calliope system was also recently installed on the 12,500-foot Laubhan Friesen well located in Blaine County, Oklahoma. The well was dead due to apparent reservoir damage from the operations of the previous owner. The objective is to attempt to use Calliope to remove an emulsion from the wellbore in order to restore production.

Joint Ventures With Third Parties In an effort to increase the number of Calliope installations, the company is seeking 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 a keen interest in Calliope, and joint venture discussions are continuing 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 resources and make efforts as it believes that the company will eventually be successful in the joint venture area.

Operations Summary.

During the past two years, the company has significantly expanded and diversified its operations with the objective of sustaining its production and reserve growth rate. The company believes that, over time, each of its four drilling projects will add significant production and reserves at a reasonable cost and risk. In particular, the company believes that the Calliope drilling project presents excellent potential for adding significant production and reserves, and that the project will allow the company to better control the monetization of its Calliope Gas Recovery technology.

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 2006 total revenues increased 24% to $16,491,000 compared to $13,289,000 last year. 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 last year. Oil and gas production expenses increased 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 increased 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.

In 2005, total revenues rose 37% to $13,289,000 compared to $9,710,000 in 2004. As the oil and gas price/volume table on page 20 shows, total gas price realizations, which reflect hedging transactions, rose 34% to $6.16 per Mcf and oil price realizations rose 39% to $50.90 per barrel. The net effect of these price changes was to increase oil and gas sales by $3,253,000. Hedging losses were $719,000 in 2005 compared to $717,000 in 2004. Gas equivalent production rose 5%. The net effect of these volume changes was to increase oil and gas sales by $523,000. Investment and other income fell 57% due primarily to decrease in investment income.

In 2005, total costs and expenses rose 25% to $6,315,000 compared to $5,032,000 in 2004. Oil and gas production expenses rose 33% due primarily to increased production taxes on higher revenues and new wells added during the year. DD&A increased 37% due to increased production volumes and an increase in costs being amortized. General and administrative expenses decreased 5% primarily due to a decrease in stock based compensation costs and an increase in reimbursed overhead. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28% in 2005 and 2004.

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 28-year history. That write-down was made in 1986 after oil prices fell 51% and natural gas prices fell 45% between fiscal year-end 1985 and 1986.

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

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

The company s reserves, and reserve values, are concentrated in 53 properties (Significant Properties). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2006, the Significant Properties represent 24% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual wells on which the company s patented liquid lift system is installed comprise 23% of the Significant Properties and represent 28% of the discounted reserve value of such properties. New wells comprise 9% of the Significant Properties and represent 20% 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 2006 by production for fiscal year 2006. This measure yields an average reserve life of 8 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 December 2004, the FASB issued SFAS No. 123 (Revised 2004), Share-Based Payment , that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for (a) equity instruments of the company or (b) liabilities that are based on the fair value of the company s equity instruments or that may be settled by the issuance of such equity instruments. SFAS No. 123R addresses all forms of share-based payment awards, including shares issued under employee stock purchase plans, stock options, restricted stock and stock appreciation rights. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25, Accounting for Stock Issued to Employees , that was provided in Statement 123 as originally issued. Under SFAS No. 123R companies are required to record compensation expense for all share based payment award transactions measured at fair value. This statement is effective for fiscal years beginning after June 15, 2005. The company implemented SFAS 123R in the first quarter of the company s fiscal year beginning November 1, 2005, using the modified retrospective-transition method. Under this transition method, the company restated the results of all prior periods back to the beginning of fiscal 1997 (the fiscal year of inception for this stock-based compensation plan) in accordance with the original provisions of SFAS No. 123.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments* (SFAS 155), which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. SFAS 155 simplifies the accounting for certain derivatives embedded in other financial instruments by allowing them to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. The statement also clarifies and amends certain other provisions of SFAS No. 133 and SFAS No. 140. SFAS 155 is effective for all financial instruments acquired, issued, or subject to a re-measurement event occurring in fiscal years beginning after September 15, 2006. We do not expect the adoption of SFAS 155 to have an impact on our results of operations or financial condition.

In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets an amendment to FASB Statement No. 140* (SFAS 156). SFAS 156 requires that all separately recognized servicing rights be initially measured at fair value, if practicable. In addition, this statement permits an entity to choose between two measurement methods (amortization method or fair value measurement method) for each class of separately recognized servicing assets and liabilities. This new accounting standard is effective January 1, 2007. We do not expect the adoption of SFAS 156 to have an impact on our results of operations or financial condition.

In June 2006, the FASB ratified the consensus reached by the EITF on EITF Issue No. 05-01, *Accounting for the Conversion of an Instrument That Becomes Convertible Upon the Issuer s Exercise of a Call Option* (EITF 05-01). The EITF consensus applies to the issuance of equity securities to settle a debt instrument that was not otherwise currently convertible but became convertible upon the issuer s exercise of call option when the issuance of equity securities is pursuant to the instrument s original conversion terms. The adoption of EITF 05-01 is not expected to have an impact on our results of operations or financial condition.

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 a 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 company is currently evaluating the impact of FIN 48 on its consolidated 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

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CONSOLIDATED BALANCE SHEETS
October 31, 2006 and 2005
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2006	2005
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 4,577,000**	$ 1,935,000
Short-term investments	**5,624,000**	5,495,000
Receivables:		
Trade	**777,000**	1,003,000
Accrued oil and gas sales	**1,963,000**	2,776,000
Derivative assets	**897,000**	
Other current assets	**71,000**	245,000
Total current assets	**13,909,000**	11,454,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**7,060,000**	3,452,000
Evaluated oil and gas properties	**43,588,000**	36,121,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(18,556,000)**	(15,022,000)
Net oil and gas properties	**32,092,000**	24,551,000
Exclusive license agreement, net of accumulated amortization of $431,000 in 2006 and $361,000 in 2005	**268,000**	338,000
Compressor and tubular inventory to be used in development	**1,293,000**	1,288,000
Other, net	**197,000**	213,000
Total assets	**$ 47,759,000**	$ 37,844,000
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	**$ 1,581,000**	$ 896,000
Revenue distribution payable	**1,273,000**	1,461,000
Other accrued liabilities	**808,000**	1,069,000
Income taxes payable	**174,000**	331,000
Total current liabilities	**3,836,000**	3,757,000
Long-term liabilities:		
Deferred income taxes, net	**8,039,000**	5,978,000
Exclusive license obligation, less current obligations of $70,000 in 2006 and $64,000 in 2005	**163,000**	233,000

Asset retirement obligation	**954,000**	929,000
Total liabilities	**12,992,000**	10,897,000
Commitments:		
Stockholders equity:		
Preferred stock, no par value, 5,000,000 shares authorized, none issued		
Common stock, $.10 par value, 20,000,000 shares authorized, 9,510,000 shares issued and outstanding in 2006 and 2005	**951,000**	951,000
Capital in excess of par value	**14,794,000**	13,935,000
Treasury stock, at cost, 249,000 shares in 2006, and 393,000 shares in 2005		(125,000)
Accumulated other comprehensive income (loss)	**650,000**	(306,000)
Retained earnings	**18,372,000**	12,492,000
Total stockholders equity	**34,767,000**	26,947,000
Total liabilities and stockholders equity	**$ 47,759,000**	$ 37,844,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three Years Ended October 31, 2006
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2006	2005	2004
Revenues:			
Oil and gas sales	**$ 15,837,000**	$ 13,143,000	$ 9,367,000
Investment and other income	**654,000**	146,000	343,000
	16,491,000	13,289,000	9,710,000
Costs and expenses:			
Oil and gas production	**3,407,000**	2,759,000	2,075,000
Depreciation, depletion and amortization	**3,642,000**	2,402,000	1,747,000
General and administrative	**1,291,000**	1,117,000	1,171,000
Interest	**42,000**	37,000	39,000
	8,382,000	6,315,000	5,032,000
Income before income taxes	**8,109,000**	6,974,000	4,678,000
Income taxes	**(2,229,000)**	(1,952,000)	(1,310,000)
Net income	**$ 5,880,000**	$ 5,022,000	$ 3,368,000
Basic income per share	**$ .64**	$ .55	$ .37
Diluted income per share	**$ .62**	$ .54	$ .36
Weighted average number of shares of common stock and dilutive securities:			
Basic	**9,207,000**	9,080,000	9,036,000
Diluted	**9,482,000**	9,367,000	9,282,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
For the Three Years Ended October 31, 2006
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock Shares	Common Stock Amount	Capital In Excess Of Par Value	Treasury Stock	Accumulated Other Comprehensive Income(Loss)	Comprehensive Income	Retained Earnings	Total Stockholders Equity
Balances, October 31, 2003	9,510,000	$ 951,000	$ 13,106,000	$ (704,000)	$ 180,000		$ 4,102,000	$ 17,635,000
Comprehensive income:								
Net income						$ 3,368,000	3,368,000	3,368,000
Other comprehensive income (loss), net of tax:								
Change in fair value of derivatives					(617,000)	(617,000)		(617,000)
Comprehensive income						$ 2,751,000		
Purchase of treasury stock				(39,000)				(39,000)
Exercise of stock options				291,000				291,000
Compensation expense related to employee stock options			282,000					282,000
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	5,022,000
Other comprehensive income (loss), net of tax:								
Change in fair value of derivates					131,000	131,000		131,000

Comprehensive income						$ 5,153,000		
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			207,000					207,000
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	5,880,000
Other comprehensive income (loss), net of tax:								
Change in fair value of derivatives					956,000	956,000		956,000
Comprehensive income						$ 6,836,000		
Exercise of common stock options			710,000	125,000				835,000
Compensation expense related to employee stock options			149,000					149,000
Balances, October 31, 2006	9,510,000	$ 951,000	$ 14,794,000		$ 650,000		$ 18,372,000	$ 34,767,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Years Ended October 31, 2006
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2006	2005	2004
Cash flows from operating activities:			
Net income	**$ 5,880,000**	$ 5,022,000	$ 3,368,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**3,642,000**	2,402,000	1,747,000
Deferred income taxes	**2,061,000**	1,373,000	1,496,000
Compensation expense related to stock options granted	**149,000**	207,000	282,000
Other	**18,000**		34,000
Changes in operating assets and liabilities:			
Proceeds from short-term investments	**551,000**	2,500,000	944,000
Purchase of short-term investments	**(680,000)**	(1,624,000)	(2,537,000)
Trade receivables	**226,000**	16,000	(609,000)
Accrued oil and gas sales	**813,000**	(725,000)	(795,000)
Other current assets	**234,000**	299,000	95,000
Accounts payable and accrued liabilities	**236,000**	(968,000)	791,000
Income taxes payable	**(157,000)**	319,000	(198,000
Net cash provided by operating activities	**12,973,000**	8,821,000	4,618,000
Cash flows from investing activities:			
Additions to oil and gas properties	**(11,746,000)**	(6,938,000)	(5,671,000)
Proceeds from sale of oil and gas properties	**670,000**	180,000	317,000
Changes in other long-term assets	**(20,000)**	(909,000)	(825,000)
Net cash used in investing activities	**(11,096,000)**	(7,667,000)	(6,179,000)
Cash flows from financing activities:			
Proceeds from exercise of stock options	**835,000**	335,000	291,000
Purchase of treasury stock		(8,000)	(39,000)
Principal payment on exclusive license obligation	**(70,000)**	(64,000)	(58,000)
Net cash provided by financing activities	**765,000**	263,000	194,000
Increase (decrease) in cash and cash equivalents	**2,642,000**	1,417,000	(1,367,000)
Cash and cash equivalents:			
Beginning of period	**1,935,000**	518,000	1,885,000

End of period	**$ 4,577,000**	$ 1,935,000	$ 518,000
Supplemental Cash Flow Information:			
Cash paid during the period for income taxes	**$ 620,000**	$ 100,000	$ 194,000
Cash paid during the period for interest	**$ 30,000**	$ 36,000	$ 41,000

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
October 31, 2006
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.
Certain financial statement amounts have been reclassified to conform the presentation used for the 2006 period. Effective with 2006, the company has reclassified reimbursed overhead from operating revenue to general and administrative expense. For the years ended October 31, 2005 and 2004 the reclassified amounts were $668,000 and $604,000 respectively.
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, 2006, approximately 60% 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.
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 in 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 28-year history. That write down was made in 1986 after oil prices fell 51% and natural gas prices fell 45% between fiscal year end 1985 and 1986.

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

Oil and Gas Reserves

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

The company s reserves, and reserve values, are concentrated in 53 properties (Significant Properties). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2006, the Significant Properties represent 24% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual wells on which the company s patented liquid lift system is installed comprise 23% of the Significant Properties and represent 28% of the discounted reserve value of such properties. New wells comprise 9% of the Significant Properties and represent 20% 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 2006 by production for fiscal year 2006. This measure yields an average reserve life of eight 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,	
	2006	2005
Beginning asset retirement obligation	**$ 929,000**	$ 748,000
Accretion expense	**40,000**	43,000
Obligations incurred	**58,000**	44,000
Obligations settled	**(58,000)**	(56,000)
Change in estimate	**(15,000)**	150,000
Ending asset retirement obligation	**$ 954,000**	$ 929,000

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 derivatives (consisting solely of cash flow hedges) on the balance sheet at fair value at the end of each period. Changes in the fair value of a cash flow hedge are recorded in Stockholders Equity as Accumulated Other Comprehensive Income(Loss) on the Consolidated Balance Sheets and then are reclassified into the Consolidated Statement of Operations as the underlying hedged item affects earnings. Amounts reclassified into earnings related to natural gas hedges are included in oil and gas sales.

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had after tax hedging losses of $191,000 in fiscal 2006, $518,000 in fiscal 2005, and $516,000 in fiscal 2004. Any hedge ineffectiveness, which was not material for the three years ended October 31, 2006, is immediately recognized in gas sales.

Hedges include contracts indexed to the NYMEX and 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 2006) and unrealized (December 2006 through July 2007) gains and losses on hedge contracts at October 31, 2006 totaled $897,000 and were included in Other Comprehensive Income . These contracts covered 950 MMBtus at NYMEX basis prices ranging from $6.25 to $9.98.

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 $4,500,000 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 unfunded debt in excess of $500,000. It expires on October 31, 2007.

Stock-Based Compensation

The company s 1997 Stock Option Plan (the Plan), as amended and restated effective October 25, 2001, authorizes the granting of incentive and nonqualified options to purchase shares of the company s common stock. 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.

Prior to November 1, 2005, the company accounted for this plan under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Statement of Financial Accounting Standards (SFAS) No. 123, Accounting for Stock-Based Compensation. No stock-based employee compensation expense was recognized in the company s Consolidated Statement of Operations prior to November 1, 2005, as all options granted under the company s stock-based compensation plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective November 1, 2005, the company adopted the fair value recognition provisions of SFAS No. 123 (R), Share Based Payment, using the modified-retrospective-transition method. Under this transition method, the company restated the results of all prior periods back to the beginning of fiscal 1997 (the fiscal year of inception for this stock-based compensation plan) in accordance with the original provisions of SFAS No. 123. The cumulative effect of this restatement was an increase of $1,447,000 to capital in excess of par value and a corresponding decrease to retained earnings.

The fair value of the 33,750 options granted during the year ended October 31, 2005 was estimated as of the grant date using the Black-Scholes option pricing model with the following assumptions: volatility, 48%; expected option term, 5 years; risk-free interest rate, 4%; and, expected dividend yield, 0%. The company did not make any option grants during fiscal 2006 or 2004. If option grants are made in the future, compensation expense for all such share-based payments granted, based upon the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R) will be included in compensation expense.

Compensation expense related to stock options included in General and Administrative Expense for the years ended October 31, 2006, 2005 and 2004 is $209,000, $288,000 and $392,000 respectively.

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

	Years Ended October 31,					
	2006		2005		2004	
	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	**485,064**	**$ 5.78**	565,875	$ 7.11	726,705	$ 4.74
Granted			33,750	8.93		
Exercised	**(143,813)**	**5.81**	(61,686)	5.43	(160,830)	1.88
Cancelled or forfeited	**(26,249)**	**8.82**	(52,875)	6.01		
Outstanding at end of year	**315,002**	**$ 5.52**	485,064	$ 5.78	565,875	$ 7.11
Exercisable at end of year	**266,939**	**$ 5.53**	348,114	$ 5.64	267,048	$ 5.55
Weighted average contractual life at end of year		**6.4**		7.7		7.8

The following Table summarizes information about stock options outstanding at October 31, 2006:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding at October 31, 2006	Weighted Average Remaining Contractual Life in Year	Weighted Average Exercise Price	Number Exercisable at October 31, 2006	Weighted Average Exercise Price
$ 3.09-$ 3.72	54,750	5.69	$ 3.56	44,625	$ 3.53

$ 5.93	260,252	6.54	$	5.93	222,314	$	5.93
$ 3.09-$ 5.93	315,002	6.39	$	5.52	266,939	$	5.53

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, 2006 were 315,002.
The company s calculation of earnings per share of common stock is as follows:

	Year Ended October 31,								
	2006			2005			2004		
	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	**$ 5,880,000**	**9,207,000**	**$ .64**	$ 5,022,000	9,080,000	$ .55	$ 3,368,000	9,036,000	$ .37
Effect of dilutive shares of common stock from stock options		**275,000**	**(.02)**		287,000	(.01)		246,000	(.01)
Diluted earnings per share	**$ 5,880,000**	**9,482,000**	**$ .62**	$ 5,022,000	9,367,000	$ .54	$ 3,368,000	9,282,000	$ .36

Recent Accounting Pronouncements
In December 2004, the FASB issued SFAS No. 123 (Revised 2004), Share-Based Payment , that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for (a) equity instruments of the company or (b) liabilities that are based on the fair value of the company s equity instruments or that may be settled by the issuance of such equity instruments. SFAS No. 123R addresses all forms of share-based payment awards, including shares issued under employee stock purchase plans, stock options, restricted stock and stock appreciation rights. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25, Accounting for Stock Issued to Employees , that was provided in Statement 123 as originally issued. Under SFAS No. 123R companies are required to record compensation expense for all share based payment award transactions measured at fair value. This statement is effective for fiscal years beginning after June 15, 2005. The company implemented SFAS 123R in the first quarter of the company s fiscal year beginning November 1, 2005, using the modified retrospective-transition method. Under this transition method, the company restated the results of all prior periods back to the beginning of fiscal 1997 (the fiscal year of inception for this stock-based compensation plan) in accordance with the original provisions of SFAS No. 123.
In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments* (SFAS 155), which amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. SFAS 155 simplifies the accounting for certain derivatives embedded in other financial instruments by allowing them to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. The statement also clarifies and amends certain other provisions of SFAS No. 133 and SFAS No. 140. SFAS 155 is effective for all financial instruments acquired, issued, or subject to a re-measurement event occurring in fiscal years beginning after September 15, 2006. We do not expect the adoption of SFAS 155 to have an impact on our results of operations or

financial condition.
In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets an amendment to FASB Statement No. 140* (SFAS 156). SFAS 156 requires that all separately recognized servicing rights be initially measured at fair value, if practicable. In addition, this statement permits an entity to choose between two measurement methods (amortization method or fair value measurement method) for each class of separately recognized servicing assets and liabilities. This new accounting standard is effective January 1, 2007. We do not expect the adoption of SFAS 156 to have an impact on our results of operations or financial condition.

In June 2006, the FASB ratified the consensus reached by the EITF on EITF Issue No. 05-01, *Accounting for the Conversion of an Instrument That Becomes Convertible Upon the Issuer s Exercise of a Call Option* (EITF 05-01). The EITF consensus applies to the issuance of equity securities to settle a debt instrument that was not otherwise currently convertible but became convertible upon the issuer s exercise of call option when the issuance of equity securities is pursuant to the instrument s original conversion terms. The adoption of EITF 05-01 is not expected to have an impact on our results of operations or financial condition.

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 a 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 company is currently evaluating the impact of FIN 48 on its consolidated 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, 2006, 9,510,000 have been issued. 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.

On March 24, 2004, the company declared a 3-for-2 stock split to shareholders of record on April 5, 2004. Accordingly, 2,006,000 additional shares were issued on April 20, 2004. Common stock has been increased by the par value of the shares issued with a corresponding decrease in capital in excess of par value.

(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 $16,000 in 2006, $32,000 in each successive year through 2010, and $16,000 in 2011. Total rental expense was $80,000 in 2006, $79,000 in 2005, and $77,000 in 2004. The company has no capital leases and no other operating lease commitments.

Total costs incurred for the South Texas project were $1,836,000 and $793,000 in 2006 and 2005, respectively. Total costs incurred for the north central Kansas project were $763,000 and $502,000 for 2006 and 2005, respectively. Such costs include overhead, lease bonuses, land services and 3-D seismic. On October 31, 2006, the company had no remaining capital commitments related to the South Texas and north central Kansas projects.

(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 2006, 2005 and 2004 were $37,000, $39,000, and $35,000, 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, 2006, 2005, and 2004 are as follows:

		October 31,	
	2006	2005	2004
Net income	**$ 5,880,000**	$ 5,022,000	$ 3,368,000
Other comprehensive income(loss):			
Change in fair value of derivatives	**1,203,000**	182,000	(857,000)
Income tax (expense) benefits	**(247,000)**	(51,000)	240,000
Total comprehensive income	**$ 6,836,000**	$ 5,153,000	$ 2,751,000

The following table sets forth a reconciliation of the company s accumulated gain(loss) on derivatives for the fiscal years ended October 31, 2005, 2004 and 2003.

		October 31,	
	2006	2005	2004
Accumulated gain (loss) on derivatives:			
Balance beginning of period	**$ (306,000)**	$ (437,000)	$ 180,000
Realization of hedging gain (losses)	**189,000**	10,000	(176,000)
Net unrealized gain (losses) on price hedge contracts	**767,000**	121,000	(441,000)
Balance end of period	**$ 650,000**	$ (306,000)	$ (437,000)

(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, 2006 the company had $1,088,000 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,		
	2006	2005	2004
Current	**$ 473,000**	$ 715,000	$ 114,000
Deferred	**1,756,000**	1,318,000	1,306,000
Total income tax expense	**$ 2,229,000**	$ 2,033,000	$ 1,420,000

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

	Years Ended October 31,		
	2006	2005	2004
Federal taxes at statutory rate	**2,838,000**	2,542,000	1,775,000
Graduated rates	(62,000)	(72,000)	(51,000)
State income taxes and other	**228,000**	143,000	105,000
Percentage depletion	**(775,000)**	(580,000)	(409,000)
	2,229,000	2,033,000	1,420,000

The principal sources of temporary differences resulting in deferred tax assets and tax liabilities at October 31, 2006 and 2005 are as follows:

	October 31,	
	2006	2005
Deferred tax assets:		
Gain on property sales	**$ 789,000**	$ 564,000
Total deferred tax assets	**789,000**	564,000
Deferred tax liabilities:		
Intangible drilling, leasehold and other exploration costs capitalized for financial reporting purposes but deducted for tax purposes	**(7,661,000)**	(5,760,000)
State taxes and other	**(1,167,000)**	(782,000)
Total deferred tax liabilities	**(8,828,000)**	(6,542,000)
Net deferred tax liability	**$ (8,039,000)**	$ (5,978,000)

(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 $882,000 has been paid. The balance, which is due in three 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, 2006	
	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:		
Exclusive license agreement	$ 699,000	$ 431,000
Aggregate amortization expense:		
For the year ended October 31, 2006		$ 70,000
Estimated future amortization expense:		
For the year ended October 31, 2007		70,000
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		$ 268,000

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, 2006, this amortizable intangible asset had a net book value of $268,000. 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, 2006, 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 certain of the company s oil and gas properties. The company has classified this amount as a long-term asset because the compressors and tubulars are not held for re-sale and the cost, net of amounts billed to joint interest owners in the normal course of business, will eventually be included in evaluated properties.

(9) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

	October 31,		
	2006	2005	2004
Unevaluated properties not being amortized	**$ 7,060,000**	$ 3,452,000	$ 2,174,000
Properties being amortized	**43,588,000**	36,121,000	30,072,000
Accumulated depreciation, depletion and amortization	**(18,556,000)**	(15,022,000)	(12,737,000)

Total capitalized costs	**$ 32,092,000**	$ 24,551,000	$ 19,509,000

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 category of cost and date 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, 2006:

Net Costs Incurred During Periods Ended:	Exploration Costs	Development Costs	Acquisition Costs	Total Unevaluated Properties
October 31, 2006	$ 2,096,000	$ 118,000	$ 2,684,000	$ 4,898,000
October 31, 2005	110,000	133,000	1,715,000	1,958,000
October 31, 2004			204,000	204,000
	$ 2,206,000	$ 251,000	$ 4,603,000	$ 7,060,000

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

	Years Ended October 31,		
	2006	2005	2004
Property acquisition costs net of divestiture proceeds:			
Proved	**$ 102,000**	$ 81,000	$ 526,000
Unproved	**1,815,000**	2,092,000	346,000
Exploration costs	**6,388,000**	834,000	1,791,000
Development costs	**2,786,000**	4,170,000	3,926,000
Total before asset retirement obligation	**$ 11,091,000**	$ 7,177,000	$ 6,589,000
Total including asset retirement obligation	**$ 11,076,000**	$ 7,327,000	$ 7,089,000

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 39% in 2006, 40% in 2005 and 40% in 2004; Enogex, Inc. 8% in 2006, 9% in 2005 and 10% in 2004.

Oil and Gas Reserve Data (Unaudited)

Independent petroleum engineers estimated proved reserves for the company s properties which represented approximately 63% in 2006, 63% in 2005 and 61% in 2004 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 $53.69, $55.59 and $50.43 per barrel for oil and $6.32, $10.26 and $5.84 per Mcf for gas in 2006, 2005 and 2004, 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.

	2006		2005		2004	
	Gas(Mcf)	**Oil(bbls)**	Gas(Mcf)	Oil(bbls)	Gas(Mcf)	Oil(bbls)
Proved reserves:						
Balance, November 1	**15,516,000**	**386,000**	15,273,000	407,000	13,786,000	385,000
Revisions of previous estimates	**(637,000)**	**24,000**	(889,000)	(6,000)	68,000	39,000
Extensions and discoveries	**3,302,000**	**53,000**	2,962,000	22,000	2,999,000	23,000
Purchases of reserves in place					130,000	1,000
Sales of reserves in place						
Production	**(2,176,000)**	**(41,000)**	(1,830,000)	(37,000)	(1,710,000)	(41,000)
Balance, October 31	**16,005,000**	**422,000**	15,516,000	386,000	15,273,000	407,000
Proved developed reserves:						
Beginning of period	**13,603,000**	**381,000**	13,993,000	374,000	13,786,000	385,000
End of period	**13,683,000**	**397,000**	13,603,000	381,000	13,993,000	374,000

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

	2006	2005	2004
Future cash inflows	**$ 123,889,000**	$ 180,726,000	$ 109,703,000
Future production and development costs	**(39,028,000)**	(43,848,000)	(32,091,000)
Future income tax expense	**(20,747,000)**	(36,054,000)	(19,965,000)
Future net cash flows	**64,114,000**	100,824,000	57,647,000
10% discount factor	**(24,363,000)**	(41,337,000)	(24,788,000)
Standardized measure of discounted future net cash flows	**$ 39,751,000**	$ 59,487,000	$ 32,859,000

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.

	2006	2005	2004
Balance, November 1	**$ 59,487,000**	$ 32,859,000	$ 21,141,000
Sales of oil and gas produced, net of production costs	**(12,430,000)**	(10,384,000)	(7,292,000)
Net changes in prices and production costs	**(33,058,000)**	29,821,000	14,919,000
	12,998,000	15,804,000	8,617,000

Extensions and discoveries, net of future development and production costs			
Changes in future development costs	**(536,000)**	(1,692,000)	(224,000)
Previously estimated development costs incurred during the period	**1,299,000**	2,248,000	304,000
Revisions of previous quantity estimates, timing, and other	**(3,396,000)**	(2,962,000)	(2,129,000)
Purchases of reserves in place			465,000
Sales of reserves in place			
Accretion of discount	**5,949,000**	3,286,000	2,114,000
Net change in income taxes	**9,438,000**	(9,493,000)	(5,056,000)
Balance, October 31	**$ 39,751,000**	$ 59,487,000	$ 32,859,000

(10) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following is a tabulation of the company s unaudited quarterly operating results for fiscal 2004, 2005 and 2006:

	Total Revenue	Income Before Income Taxes	Net Income	Basic Net Income Per Share	Diluted Net Income Per Share
Fiscal 2004:					
First Quarter	$ 2,713,000	$ 1,519,000	$ 1,094,000	$ 0.12	$ 0.12
Second Quarter	2,118,000	995,000	716,000	0.08	0.08
Third Quarter	2,287,000	1,021,000	735,000	0.08	0.08
Fourth Quarter	2,592,000	1,143,000	823,000	0.09	0.08
	$ 9,710,000	$ 4,678,000	$ 3,368,000	$ 0.37	$ 0.36
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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

To the Board of Directors and Stockholders
CREDO Petroleum Corporation and Subsidiaries

We have audited the consolidated balance sheets of CREDO Petroleum Corporation and subsidiaries as of October 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended October 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2006, 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), the effectiveness of the Company s internal control over financial reporting as of October 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated January 23, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ HEIN & ASSOCIATES LLP

HEIN & ASSOCIATIONS LLP

Denver, Colorado
January 23, 2007

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Statement of Management s Responsibility

CREDO s management has always assumed ultimate responsibility for compliance with the company s established financial accounting policies and for reporting the company s results with objectivity and a high degree of integrity. It is critical for investors and other users of the Consolidated Financial Statements to have confidence that the company s financial information is timely, complete, relevant and accurate. Management is responsible for the fair presentation of CREDO Petroleum Corporation s Consolidated Financial Statements, in accordance with generally accepted accounting principles (GAAP), and is ultimately responsible for their integrity and accuracy.

Management, with oversight by CREDO s Board of Directors, has established and maintains a strong ethical climate so that the company s affairs are conducted to high standards. Management is also ultimately responsible for an effective system of internal control over financial reporting. CREDO s policies and practices reflect corporate governance initiatives that are compliant with the listing requirements of NASDAQ and the corporate governance requirements of the Sarbanes-Oxley Act of 2002.

Management is committed to enhancing shareholder value and fully understands and embraces its fiduciary oversight responsibilities. Management is dedicated to ensuring that high standards of financial accounting and reporting as well as the underlying system of internal controls are maintained. This culture demands integrity and management has the highest confidence in the company s process, its internal controls, and its people, who are objective in their responsibilities and who operate under the highest level of ethical standards.

Management s Report on Internal Control Over Financial Reporting

Management is ultimately responsible for establishing and maintaining adequate internal control over financial reporting for CREDO. 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. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records which in reasonable detail accurately and fairly reflect the transactions and dispositions of the company s assets; (ii) 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 in accordance with established company policies and procedures; and (iii) 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 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.

Management (with the participation of the principal executive officer and principal financial officer) conducted an evaluation of the effectiveness of the company s internal control over financial reporting based on the framework set forth in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the company s internal control over financial reporting was effective as of October 31, 2006. Management s assessment of the effectiveness of the company s internal control over financial reporting as of October 31, 2006 has been audited by Hein & Associates, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors Credo Petroleum Corporation and Subsidiaries

Denver, Colorado

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting that Credo Petroleum Corporation and Subsidiaries (Credo) maintained effective internal control over financial reporting as of October 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Credo 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and 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.

In our opinion, management s assessment that Credo maintained effective internal control over financial reporting as of October 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control-Integrated Framework issued by COSO. Also in our opinion, Credo maintained, in all material respects, effective internal control over financial reporting as of October 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of Credo Petroleum Corporation and subsidiaries and our report dated January 23, 2007 expressed an unqualified opinion.

/s/ Hein & Associates LLP
Denver, Colorado
January 23, 2007

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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 ACCOUNTING 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 23, 2007 and is hereby incorporated by reference.

PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements:
Consolidated Balance Sheets October 31, 2006 and 2005
Consolidated Statements of Operations Three Years ended October 31, 2006
Consolidated Statements of Shareholders Equity Three Years ended October 31, 2006
Consolidated Statements of Cash Flows Three Years ended October 31, 2006
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).

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 6, 2006 (filed herewith).
31.1 *	Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2 *	Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
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 herewith)

* 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 23, 2007.

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 23, 2007	/s/ James T. Huffman	Chairman of the Board
	James T. Huffman	of Directors, President, Treasurer and Chief Executive Officer (Principal Executive Officer)
January 23, 2007	/s/ David E. Dennis	Chief Financial Officer
	David E. Dennis	(Principal Financial and Accounting Officer)
January 23, 2007	/s/ Clarence H. Brown	Director
	Clarence H. Brown	
January 23, 2007	/s/ Oakley Hall	Director
	Oakley Hall	
January 23, 2007	/s/ William F. Skewes	Director
	William F. Skewes	
January 23, 2007	/s/ Richard B. Stevens	Director
	Richard B. Stevens	

Exhibit Index

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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 herewith)

* Filed with this Form 10-K.