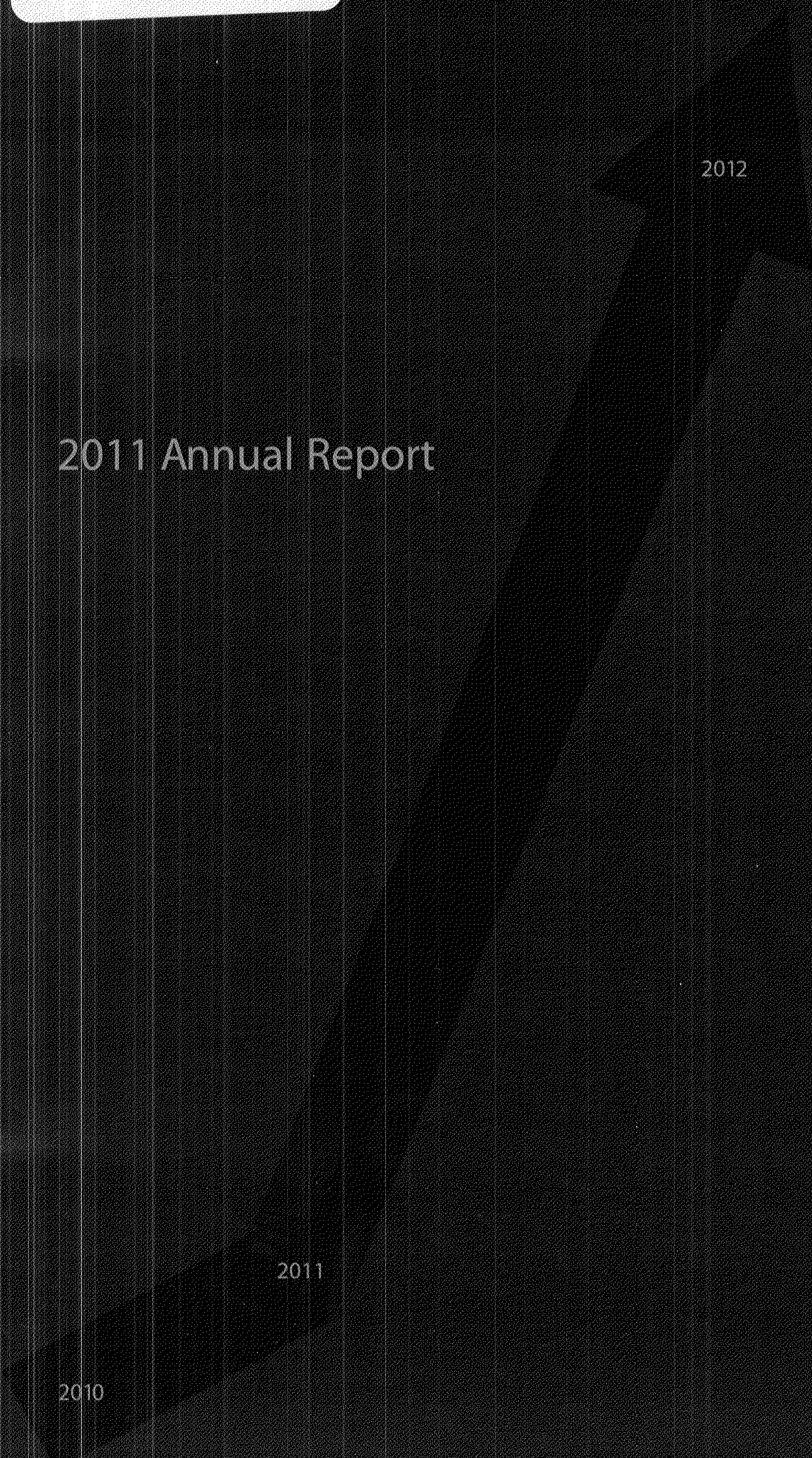


2011 Annual Report

CREDO

Highlights

	4th Quarter 2011	Fiscal Year 2011
Revenue	Up 94%	Up 45%
Net Income	Up 242%	Up 60%
EBITDA	Up 116%	Up 55%
Production	Up 32%	Up 12%
Proved Reserves	*	Up 25%
Proved Oil Reserves	*	Up 106%
PV 10 Reserve Value	*	Up 61%

* Quarterly calculation is not applicable because year-end and fourth quarter reserves are the same.

About the cover: The arrow on the cover represents the growth in Credo's Drilling Budget, from $8.7 million in 2010 to $15.5 million in 2011 to a planned $35 million in 2012 — more than 300% growth over two years

Fellow Shareholders:

We continued to achieve major transition milestones in 2011 which generated the excellent financial and operational results shown on the inside front cover. For the past three years our business strategy has been to rapidly transform Credo from almost exclusively a natural gas producer into primarily an oil producer. We began executing on that strategy by entering then emerging drilling plays in the North Dakota Bakken and Three Forks and the Tonkawa and Cleveland in the Texas Panhandle. We also entered a vertical oil drilling play in Kansas and Nebraska. While major transitions like this require a rebuilding period, we are pleased to report that a majority of our revenues and production now come from oil, and that all of our performance metrics are on the threshold of becoming oil weighted.

Successful drilling in 2011 drove significantly improved operating results and achieved the milestone of relative equilibrium in our oil and gas production and reserves.

In 2011, we almost doubled capital spending to $15.5 million and drilled a record 49 gross (20 net) oil wells, a 92% increase in net wells over last year. As a result we added significant oil production and reserves, bringing the oil and gas mix for both categories into relative balance.

Successful drilling results drove a 12% year over year increase in total production volumes to 301,000 BOE. The following table shows comparative year production volume percentages by region.

	2011	2010
North Dakota Bakken and Three Forks	12%	2%
Kansas and Nebraska Lansing Kansas City	20%	16%
Texas Panhandle Tonkawa and Cleveland	8%	4%
Other (primarily Oklahoma natural gas)	60%	78%

Our oil production increased 53% compared to last year. We suspended gas drilling in 2009 because of low natural gas prices. As a result, mostly normal declines reduced gas production by 12% in 2011. The decline in gas production substantially offset the larger increase in oil production because (as the table below shows) at the beginning of 2011 gas represented almost two-thirds of our production volume. That situation will significantly improve in 2012 as we enter the year with oil and gas production quantities about equal. The following table shows comparative year production percentages by product.

	2011	2010
Crude Oil and NGLs	49%	36%
Natural Gas	51%	64%

Total reserve additions for 2011 were 1.1 million barrels of oil equivalent ("MMBOE"), replacing 372% of the year's production. At year end, proved reserves totaled 4.1 MMBOE, up 25% over last year. Oil represented 48% of year-end reserve quantities compared to 29% last year. We expect to achieve the milestone of oil becoming the largest component of reserve quantities in early 2012. The following table shows the percentage of our year-end proved reserve quantities by region.

	2011	2010
North Dakota Bakken and Three Forks	32%	8%
Kansas and Nebraska Lansing Kansas City	8%	7%
Texas Panhandle Tonkawa and Cleveland	7%	10%
Other (primarily Oklahoma natural gas)	53%	75%

At year end 2011, the Company's proved reserves had a PV-10 value (SEC basis) of $62.3 million, up 61% over last year. Oil represented 74% of reserve values compared to only 48% of reserve quantities due to the significant price differential between oil and natural gas. Proved undeveloped reserves represented 51% of total 2011 reserves. The percentage of proved undeveloped reserves increased primarily because a significant amount of drilling occurred around our Bakken acreage which proved-up drilling locations on our acreage.

Based on actual production information from our wells, Credo's "in-house" Bakken reserve estimates are in line with some of the larger Bakken operators who are estimating per well reserves of around 600,000 BOE. By comparison, our independent engineers are currently giving our wells average reserves of 351,000 BOE. We, therefore, expect our reported (SEC basis) per well Bakken reserves to increase with time as more production history becomes available in our area.

Successful and cost efficient operating results lead to significantly improved financial performance.

Oil-weighted production growth, operating efficiency and supportive oil prices resulted in Credo generating $9,967,000 in EBITDA for 2011, a 55% increase over 2010. For 2011, the Company reported a 60% increase in net income to $3,518,000, or $.35 per diluted share. Revenues increased 45% to $16,767,000 compared to last year, and the company continued to maintain a strong balance sheet and financial position.

Our fourth quarter results reflect the build-up of new oil production and reserves as the year progressed.

Record drilling drove sequential production increases in each quarter of 2011. As the table on the inside front cover shows, the resulting increases in our comparative fourth quarter performance metrics were substantially better than for the full year. Credo achieved the milestone of becoming primarily an oil producer in the fourth quarter, when oil production represented 56% of production quantities and 79% of revenues. Total fourth quarter production increased 32% year over year, and 12% sequentially. The Bakken and Three Forks comprised 11% of fourth quarter production compared to 4% last year. Average daily production increased to 943 BOEPD in the fourth quarter.

For the fourth quarter, Credo generated $3,214,000 in EBITDA, a 116% increase over last year. Fourth quarter net income increased 242% to $1,387,000, or $.14 per diluted share. Fourth quarter revenue increased 94% to $4,961,000.

We enter 2012 with diversified drilling projects, hundreds of de-risked drilling locations and a positive outlook for oil prices.

Now that we have achieved relative balance in the oil and gas mix of our production and reserves, the next milestone is to significantly overweight oil in the mix. To accomplish that goal, we will continue to ramp-up oil drilling in 2012 by more than doubling Credo's drilling budget to $35,000,000. As a result, we will set new drilling records, with 85 gross (37 net) oil wells currently on our drilling schedule, representing an 85% increase in net wells over 2011. The regional allocation of our 2012 and 2011 drilling budget is shown below (in millions).

	2012	2011
North Dakota Bakken and Three Forks	$ 22.4	$ 4.8
Kansas and Nebraska Lansing Kansas City	9.8	8.4
Texas Panhandle Tonkawa and Cleveland	1.4	2.0
Other (primarily Oklahoma natural gas)	1.4	.3
	$ 35.0	$ 15.5

Technology will continue to drive Credo's drilling success. Horizontal drilling is a key to success in the North Dakota Bakken and Three Forks and in the Texas Panhandle Cleveland and Tonkawa oil plays. In Kansas and Nebraska we are successfully using 3-D seismic to identify structural features likely to trap oil. We are also continuing to deploy our patented Calliope Gas Recovery System for low pressure gas reservoirs

Credo's Bakken leases are located in the heart of the play where recent drilling has significantly de-risked our acreage.

The Bakken is the largest onshore crude oil accumulation ever assessed by the United States Geological Survey. We are seeing a dramatic increase in drilling on and around Credo's acreage, virtually all of which is located in the heart of the play on the Fort Berthold Reservation. Credo owns approximately 8,000 gross (6,000 net) acres consisting of approximately 57 initial well spacing units based mostly on 1,280 acre spacing. We currently classify 50 of the spacing units as prime. While our interest in individual spacing units differs, our average working interest is 9%. We believe that at least two Bakken and two Three Forks wells are likely to be drilled on most of our spacing units for a total of 200 to 250 wells. However, many of the larger Bakken operators predict that up to eight wells could ultimately be drilled in the primary Bakken and Three Forks zones, which could double potential Company wells to 400 to 500.

Our Bakken and Three Forks project is particularly exciting because we are participating with highly experienced operators in a repeatable and scalable world class oil play. Drilling on our acreage is in its infancy, but is ramping-up fast. To date, Credo has completed 12 Bakken and Three Forks wells, all high rate producers, and we currently project at least 20 new wells in fiscal 2012, for a total of 32 wells by year end 2012. The Company's average working interest in the wells is 9.1%. Seven of the 20 wells projected for 2012 are currently in various stages of being drilled or completed. Three of the wells target the Three Forks formation and four target the Bakken formation.

A hallmark of outstanding oil plays, like the Bakken and Three Forks, is that they get better with time as operators continue to crack the code on how to efficiently recover the oil in place. For example, other operators are now testing the Lower Three Forks benches with initial positive results.

Diversification is essential to properly manage risks, and creates staying power in the event of regional disruptions.

We are continuing to lease aggressively in Kansas and Nebraska, and now own 147,000 gross (85,000 net) acres. Our exploration team has created a statistically repeatable exploration model using advanced 3-D seismic technology and subsurface geology. To date, we have drilled 114 wells and continue to achieve very favorable results and excellent risk adjusted economics. Our exploration team is applying its considerable experience from Kansas to decode the potential in Nebraska.

In the Texas Panhandle, Credo's acreage position consisting of 8,500 gross (2,400 net) acres lends itself to impactful, multi-pay, horizontal drilling for the oil-rich Tonkawa and Cleveland formations. Located in the Tonkawa fairway, our first two horizontal Tonkawa wells continue to be strong producers, and our first horizontal Cleveland well is scheduled to spud this spring. We see potential for 15 to 20 horizontal wells on our acreage, and estimate Credo's average ownership to be between 25% and 30%.

In 2011, Credo took advantage of opportunities created by low natural gas prices to buy wells for application of its patented Calliope Gas Recovery System. We have dedicated a team to Calliope with the objective of acquiring Calliope candidates, as companies de-emphasize natural gas and "offload" gas properties while shifting to oil development.

We own approximately 70,000 gross acres in Oklahoma, most of which is natural gas prone. There is ample development potential on our acreage when gas prices recover. Most of the acreage is held by production, and thus the timing of drilling is not critical to our lease ownership position.

We have built an excellent growth platform of scalable and repeatable drilling projects which will drive Credo's long-term success.

A balanced, multi-year inventory of development, exploitation, and exploration projects will propel Credo's organic production and reserve gains in the years ahead. The substantial increase in our drilling and leasing budgets will further accelerate our growth trajectory and drive earnings and shareholder returns.

While we expect to borrow between $7 and $12 million in 2012 to finance our drilling programs, our Board and management are acutely aware of the Company's time-honored commitment to profitability and financial strength.

Marlis Smith stepped down as CEO in January to devote full time to rapidly accelerating drilling activity in his personal business. Marlis did an excellent job of executing our drilling program which proved our technical concepts and converted our projects into repeatable and scalable exploration plays. We are grateful for his two years of leadership, and we are pleased that Credo will continue to benefit from his knowledge and experience as a Board member.

The Board believes that Credo has a number of viable go-forward options. Accordingly, in addition to initiating a CEO search, the Board is taking the opportunity to consider other strategic options which may be available to the Company. During this process, Credo's Chief Operating Officer, Michael Davis, will also serve as interim Chief Executive Officer.

We thank our employees and our owners for your continued loyalty and support.

Michael D. Davis
Interim CEO and COO

James T. Huffman
Chairman of the Board

February 1, 2012

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

Received SEC

MAR 19 2012

Washington, DC 205

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Fiscal Year Ended October 31, 2011

or

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

For the transition period from ____________ to ____________

Commission File Number 0-8877

CREDO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. __X__ Yes _____ No

Indicate by checkmark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). __X__ Yes _____ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (S229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. __X__

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

Large accelerated filer __ Accelerated filer _X_ Non-accelerated filer __ Smaller reporting company

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of April 30, 2011, the end of the registrant's most recently completed second quarter was $81,621,000.

As of January 4, 2012, the registrant had 10,041,000 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 end 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 April 5, 2012 and is hereby incorporated by reference.

NON-GAAP FINANCIAL MEASURES

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

Estimated Future Net Revenues Discounted at 10% is not a GAAP measure of operating performance. This pre-tax, non-GAAP measure is used by the Company in connection with estimating funds expected to be available in the future for drilling and other operating activities. See Item 2 PROPERTIES, Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues for a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note 13 to the Company's Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

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

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

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

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

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

TABLE OF CONTENTS

PART I

ITEM 1. BUSINESS

General

Credo Petroleum Corporation ("Credo") was incorporated in Colorado in 1978 and reincorporated in Delaware in 2009. Credo and its wholly owned subsidiaries, SECO Energy Corporation and United Oil Corporation ("SECO", "United" and collectively "the Company"), are headquartered in Denver, Colorado. The Company is engaged in the exploration for and the acquisition, development and marketing of crude oil and natural gas in the Mid-Continent and Rocky Mountain regions and is currently conducting oil-focused drilling projects in North Dakota Bakken and Three Forks, Kansas, Nebraska and Texas Panhandle plays. Credo uses advanced technologies to systematically explore for oil and gas and, through its patented Calliope Gas Recovery System, to recover stranded reserves from depleted gas reservoirs. Credo is an active operator in Kansas, Nebraska, Wyoming, Colorado and Texas. United is an active operator doing business primarily in Oklahoma, and SECO primarily owns royalty interests in the Rocky Mountain region. The Company has operating activities in nine states and has 15 employees. References to years as used in this report indicate fiscal years ended October 31.

Business Activities

Credo is engaged in the exploration for, acquisition of, and production of crude oil, natural gas and natural gas liquids. As used in the Form 10-K, the term "oil" or "crude oil" refers to both crude oil and natural gas liquids. The Company acts as the "operator" of approximately 108 wells pursuant to standard industry operating agreements. The Company owns working interests in about 337 producing wells and overriding royalty interests in about 1,200 wells.

In recent years, the Company has made significant strategic changes with the objective of transitioning its production and reserves from virtually all natural gas to being primarily oil. This strategic decision was made because the Company believes that oil will continue to maintain a significant Btu price premium over U.S. sourced natural gas. To accomplish this objective, the Company implemented new conventional exploration projects in Kansas and Nebraska, and new horizontal exploration prospects in the North Dakota Bakken and Three Forks shale-oil play and the Texas Panhandle. These strategic changes are also intended to diversify the Company's drilling projects both geographically and scientifically. Refer to the "Certain Significant Effects of the Company's Strategic Transition from Oil to Natural Gas" section of Item 7, Management Discussion and Analysis, for further information regarding these strategic changes.

The Bakken and Three Forks play involves horizontal drilling where wells are typically drilled to a measured depth of about 20,000 feet (10,000 feet vertical and 10,000 feet horizontal). Individual wells currently cost about $10,000,000. The Company expects virtually all of its Bakken and Three Forks wells to be completed as producers. Drilling in Kansas and Nebraska is conventional vertical drilling mostly for the Lansing Kansas City formation at 4,000 to 5,000 feet. Completed wells cost about $450,000. The Kansas and Nebraska play is primarily exploratory and the Company's current success rate ranges between 40% and 45%. At current oil prices, the risk adjusted economics for both plays are very good.

Prior to 2008, the Company's core drilling region was the northern shelf of the Anadarko Basin in Oklahoma where it explored primarily for natural gas. As a result, the Company's production and reserves have historically been heavily weighted in favor of natural gas. However, at the end of fiscal 2011, the Company has achieved relative balance between oil and natural gas in both its production and reserves. It is the Company's intent to focus almost exclusively on drilling for oil in order to continue to increase the percentage of oil in both its production and reserves. Depending on natural gas prices, the Company will again generate prospects and conduct drilling on its core natural gas-prone acreage in Oklahoma, concentrating on medium depth properties.

The Company also owns the patents covering its Calliope Gas Recovery System™ ("Calliope"). Calliope efficiently lifts fluids from wellbores using pressure differentials, thus allowing gas previously trapped by fluid build-up in the wellbore to flow to the surface. Calliope is distinguished from 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 proven Calliope's economic viability and flexibility over a wide range of applications. Calliope's low per-unit finding and production costs have become increasingly attractive as the economics on many gas drilling projects have deteriorated due to low natural gas prices. The Company also believes that lower natural gas prices may stimulate divestitures of marginal properties by other companies, including properties that have Calliope potential

For additional information, refer to Item 2, "Properties" and to the "Drilling Activities" section of Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations", (hereinafter referred to as "MD&A").

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, speculation, market prices, regulation, and actions of major foreign producers.

Oil price fluctuations can be extremely volatile as has been demonstrated during the past five years when NYMEX prices have ranged from $35 to over $140 per barrel. Oil prices on the NYMEX have recently fluctuated between $75 and $105 per barrel. Oil production is generally sold to crude oil purchasing companies pursuant to one year contracts at competitive market prices for the area. Crude oil and condensate production are readily marketable, and the Company is generally not dependent on a single purchaser. Absent wars and other events of conflict, crude oil prices are mostly 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. In recent years, U.S. Mid-Continent oil prices have been affected by increasing supplies from Bakken shale-oil development and from Canada which have resulted in high inventories and bottlenecks at the Cushing Oklahoma NYMEX hub.

The active U.S. spot market for natural gas, changes in supply and demand for natural gas, speculation, and weather patterns cause natural gas prices to be subject to significant fluctuations. The Company presently sells virtually all of its natural gas pursuant to three 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.

The economic downturn that commenced in the second half of 2008 resulted in a significant reduction in industrial demand for natural gas at the same time gas supplies were significantly increasing due to horizontal drilling success in shale-gas plays. Those events caused an over supply of natural gas with the result that natural gas prices have remained depressed through 2011. The Company expects U.S. natural gas supplies to continue to be ample for the foreseeable future but cannot reasonably predict the extent or timing of natural gas price fluctuations.

As discussed in Note (5) to the Consolidated Financial Statement, the Company periodically hedges the price of a portion of its estimated production based primarily on NYMEX futures prices using forward short positions and costless collars. Information concerning the Company's major customers is included in Note (12) 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 greater 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. 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 2012. 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, the value of its reserves 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.

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 its 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.

The Company will utilize debt financing for partial funding of its 2012 drilling and exploration program.

For the first time in the Company's history, financing is expected to be required to fund a portion of the Company's fiscal 2012 drilling budget. The Company has approved a drilling budget of $30,000,000 for fiscal 2012, which is about double last year's drilling budget. Two thirds of the

2012 drilling budget is earmarked for drilling in the Bakken and Three Forks project. Subsequent to fiscal 2011 year end, the Company has entered into an oil and gas reserves borrowing base revolving credit line with its principal bank. The initial borrowing base is $7 million but may be extended twice a year. Borrowing in 2012 is expected to range from $7 million to $12 million. The financing agreement is pending final execution of the paperwork. In future years, the Company reasonably expects that additional financing, either debt or equity, will be required. See additional information below regarding uncertainties related to the timing and costs of Bakken and Three Forks drilling due to the Company being a non-operator, and additional information below regarding projected capital expenditures and capital requirements. See Note 6 to the Consolidated Financial Statements for further information regarding debt financing.

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

- the Company's success in locating and producing new reserves;
- the level of reserves and production related to existing wells;
- the prices of oil and natural gas; and
- the terms of available financing.

Issuing equity securities to satisfy the Company's cash flow needs could cause substantial dilution to existing stockholders. Debt financing may make the Company more vulnerable to competitive pressures and economic downturns.

The Company is a non-operator in the North Dakota Bakken and Three Forks oil-shale play.

The Company is not the "operator" for its Bakken and Three Forks acreage and is, therefore, not in control of the timing and amount of expenditures. Larger companies with more experience drilling and operating Bakken and Three Forks wells are the "operators" of the spacing units which include the Company's leases because such companies generally own the majority (or a very large interest) in the spacing unit. The primary advantages to the Company are as follows: (i) the larger companies have much larger staffs than the Company which include people who specialize in many of the individual technical aspects of horizontal Bakken and Three Forks drilling and operations, and (ii) the larger companies generally operate many wells in the Bakken and Three Forks play and thus have the ability to compete for oil field services and product markets more effectively than the Company. The primary disadvantage of the Company being a non-operator in the Bakken and Three Forks play is that the Company is not in control of timing of drilling operations or the costs of drilling and operating the wells, and therefore, cannot reasonably predict such timing and costs until well proposals are received from the operators.

In the event the Company does not meet its plan for future Calliope installations, it may be required to record an impairment of the asset.

The patents underlying Calliope are carried as a non-current asset on the Company's balance sheet and are being amortized over the average remaining life of the patents. The Company periodically evaluates this asset for realizability. The Company believes that the number of future installations will be sufficient to demonstrate recoverability of the cost. If the Company is unable to achieve the expected level of installations, it may in the future be required to record an impairment of the asset. Any such write-down would be a non-cash charge to income and would have no effect on working capital.

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. A 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 related to the evaluation of available geological, geophysical, engineering and economic data.

Reserve estimates are dependent on many variables, many of which are beyond the Company's control. Therefore, as more information becomes available, it is reasonable to expect actual future production, oil and natural gas prices, revenues, taxes, development expenditures , operating expenses and quantities of recoverable oil and natural gas reserves will vary from the estimates, including the timing of expenditures and revenue receipts. Any significant variance could materially affect the estimated quantities and the present value of reserves disclosed by the Company. Reserve estimates and valuations will be adjusted in the future as more information becomes available.

As of October 31, 2011, approximately 51% 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 the related wells are drilled. 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's independent engineers have prepared estimates of its proved undeveloped reserves and the associated development costs in accordance with industry standards, actual results are likely to vary from those estimates.

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 is also required to base the PV-10 on average prices it receives on the first day of each of the preceding twelve months and costs as of the date of the reserve estimate. Actual future prices and costs may be materially higher or lower. In addition to the price volatility factors discussed above, the following factors, among others, 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.

Full cost pool ceiling subject to reserve values.

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 depreciated and depleted on an aggregate basis using the units-of-production method.

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

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

The Company's reserves, and reserve values, are concentrated in 79 properties which represent 23% of the Company's total properties but a disproportionate 80% of the discounted value (at 10%) of the Company's reserves. Reserves related to new wells, including wells in the proved developed non-producing and proved undeveloped categories, comprise 27% of significant properties and 30% of the discounted value of significant properties. Due to limited or no production history, reserve estimates for those categories are based primarily on volumetric estimates which are subject to significant change as more data becomes available.

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.

Oil and natural gas short sale and collar derivatives involve credit risk and place an upper limit on future revenues from price increases.

To manage the Company's exposure to price risks associated with the sale of oil and natural gas, the Company periodically enters into derivative hedging transactions for a portion of its estimated production. While such transactions limit the Company's exposure to price decreases, they also place an upper limit on the Company's potential gains if product prices were to rise over the price established by the derivatives. In addition, such transactions could expose the Company to the risk of financial loss in certain circumstances, including instances in which:

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

The terms of the Company's derivative 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. In such event, the Company has the option to obtain funding through its financing agreement.

The Company's natural gas derivatives are generally based on NYMEX prices but the Company's hedged natural gas production is primarily sold on a regional pipeline index price. The regional price is currently about 5% below NYMEX prices. Regional weather conditions and other economic factors can frequently result in substantially higher basis differentials. Oil derivatives generally are in the form of costless collars or forward short positions and are also generally based on NYMEX pricing.

The Company has elected not to designate its commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on its Balance Sheets and changes in fair value are recorded in the Statements of Operations as they occur.

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 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. The occurrence of a significant event that is not fully insured could have a material adverse effect on the Company's financial position and results of operations.

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

The Company has recently expanded the volume and breadth of its exploration program with new drilling projects in North Dakota, Kansas and Nebraska, and the Texas Panhandle. Compared to the Company's conventional drilling, the Texas Panhandle and North Dakota horizontal drilling projects are substantially more expensive to lease, drill and operate.

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 regulations relating to:

- 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.

The Company could incur liability for violations of these regulations. In addition, because current regulations covering the Company's operations are subject to change at any time, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

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

ITEM 2. PROPERTIES

General

Refer to Item 1.—"Business Activities" for a general description of the Company's oil and gas drilling and Calliope projects. For additional information on the Company's drilling activities, refer to Item 7, "Drilling Activities" in the MD&A section.

The Company owns working interests in approximately 337 producing wells and overriding royalty interests in about 1,200 wells. It acts as the "operator" for approximately 108 of the working interest wells pursuant to standard industry operating agreements.

In North Dakota's Bakken and Three Forks shale-oil play, the Company has assembled approximately 8,000 gross (6,000 net) acres in a core area of the play. Virtually all of the acreage is located on the Fort Berthold Reservation, south and west of the Parshall Field. The acreage consists of approximately sixty two (62) spacing units where the Company's interests range from very small to 20%. The Company currently owns interests in 12 gross (.9 net) producing oil wells with an average working interest of 7.2%. In all cases, where a well has been drilled on a spacing unit, the Company expects additional development wells to be drilled on those spacing units.

In Kansas and Nebraska, the Company owns interests in approximately 147,000 gross (85,000 net) acres and it is continuing to expand its acreage position. Kansas acreage is located on the Central Kansas Uplift and in the western Kansas counties of Logan, Lane, Thomas and Gove. The Nebraska acreage is located in the southwest portion of Nebraska in the counties of Dundee, Red Willow and Hitchcock. The Company owns interests in approximately 43 gross (17 net) producing oil wells with an average working interest of 40%. Kansas and Nebraska currently represent a core drilling area for the Company, and the Company is continuing to expand its undeveloped acreage position in this play.

In the Texas Panhandle, the Company owns an average 33% working interest in about 3,000 gross acres located in Lipscomb and Hemphill counties. The area contains producing wells completed in the Morrow, Tonkawa and Cleveland formations. The Company currently owns interests in two gross (0.5 net) producing horizontal Tonkawa wells with an average working interest of 23%. The Company also owns interests in 12 gross (.9 net) producing vertical wells with an average working interest of 7%.

The Company owns leasehold interests in approximately 70,000 gross acres primarily located on the northern shelf of the Anadarko Basin of Oklahoma, where it also owns interests in approximately 226 gross (71 net) producing wells with an average working interest of 31%. The wells are primarily natural gas wells. Prior to 2008, the Company's drilling was focused on this natural gas-prone area. When natural gas prices collapsed in 2008, the Company shifted its drilling focus to oil and away from natural gas. Future drilling on the Oklahoma acreage is primarily dependent on natural gas prices. However, because most of acreage is held by production, the timing of drilling is not critical to maintaining the Company's leasehold ownership.

The Company owns the patents covering Calliope, together with the exclusive rights to the technology. Calliope efficiently lifts fluids from wellbores using pressure differentials, thus allowing gas previously trapped by fluid build-up in the wellbore to flow to the surface. Calliope is distinguished from all other fluid lift technologies because it does not rely on bottom-hole pressure and has only one down-hole moving part. Calliope is primarily applicable to mature natural gas wells in low pressure, natural gas expansion reservoirs at depths below 8,000 feet. The Company has proven that Calliope will add 0.5 to 2.0 billion cubic feet (Bcf) of proved gas reserves to many dead and uneconomic wells. The Company believes there are presently many wells that meet its general criteria for Calliope candidate wells and thousands more that will meet the criteria in the future. The Company has proven Calliope's economic viability and flexibility over a wide range of applications.

The Company currently has Calliope installed on 15 wells located in Oklahoma and Texas where it owns a average 76% working interest. In November 2008, the Company purchased all of the patents underlying Calliope, all related third party interests in future installations, and the patents covering a new fluid lift technology for shallow wells known as Tractor Seal for $4,500,000.

Refer to the "Productive Wells and Developed Acreage" and "Undeveloped Acreage" sections of this Item 2. for further information regarding the Company's properties.

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

The Company's reserves, and reserve values, are concentrated in 79 properties which represent 23% of the Company's total properties but a disproportionate 80% of the discounted value (at 10%) of the Company's reserves. Reserves related to new wells, including wells in the proved developed non-producing and proved undeveloped categories, comprise 27% of significant properties and 30% of the discounted value of significant properties. Due to limited or no production history, reserve estimates for those categories are based primarily on volumetric estimates which are subject to significant change as more data becomes available.

Effective October 31, 2010, Credo adopted revised oil and gas disclosure requirements set forth by the SEC in Release No. 33-8995, "Modernization of Oil and Gas Reporting" and as codified by the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) Topic 932, "Extractive Industries – Oil and Gas." The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures. The Company has elected not to disclose probable or possible reserves for several reasons, including the cost of preparing such data and the risks associated with estimating probable and possible reserves.

All of the Company's reserves are located within the continental United States. LaRoche Petroleum Engineers, LLC (LaRoche) and Netherland, Sewell and Associates, Inc. (NSA), independent petroleum engineering consulting firms, prepared the Company's estimated reserves as of October 31, 2011. NSA prepared the estimated reserves for the properties located in the North Dakota Bakken and Three Forks properties. LaRoche prepared the estimated reserves for all other properties. For the years ended October 31, 2010 and 2009 LaRoche prepared the estimated reserves for all of the Company's properties. The Company did not place any limitations on LaRoche or NSA in determining their reserve estimates. The Company provided certain information to LaRoche and NSA to assist in their preparation of the Company's reserve estimates.

LaRoche and NSA prepare reserve estimates for the Company based upon, among other things, review of the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geosciences and engineering data, offsetting wells and drilling, and other information that they obtain independently or that the Company provides to them. Prior to submission of any information by the Company, it is reviewed by knowledgeable members of our staff to ensure its reasonable and material accuracy and completeness. After LaRoche and NSA evaluate the data that they consider material and relevant, they issue preliminary reports containing their independent estimates of the Company's reserves. The preliminary reports are reviewed by the Company's Engineering Manager and President for reasonable and material completeness of the data presented and reasonableness of the results obtained. Once any questions have been addressed, LaRoche and NSA issue the final reports, reflecting their conclusions.

The Company's Engineering Manager, Kenneth J. DeFehr, is a Registered Professional Engineer with more than 35 years of experience in the oil and gas industry. Mr. DeFehr received a Masters Degree in Civil Engineering from Texas A&M University in 1973, and began his petroleum engineering career with Phillips Petroleum where he worked from 1974 to 1982 in the Mid-Continent, Rockies, North Sea, and research and development. Mr. DeFehr served as Senior Petroleum Engineer for Axem Resources in Denver from 1982 to 1990, and has served as Engineering Manager for Credo Petroleum since 1990. During his career, Mr. DeFehr has been involved in exploration and development, property acquisitions, waterflooding, drilling and production operations, and reserve evaluations.

Letters which identify the professional qualifications of the individuals at LaRoche and NSA who were responsible for overseeing the preparation of the Company's reserve estimates as of October 31, 2011 have been filed as addendums to Exhibit 99.1 to this report.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our properties.

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 (12) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $86.32, $68.30, and $69.24 per barrel of oil and $4.54, $4.49, and $4.49 per Mcf of gas as of October 31, 2011, 2010, and 2009, respectively. Amounts do not include estimates of future Federal and state income taxes.

Year	Oil (bbls)	Gas (Mcf)	BOE (1) (2)	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2011	**1,963,000**	**12,791,000**	**4,095,000**	**$ 116,317,000**	**$ 62,348,000**
2010	954,000	13,938,000	3,277,000	$ 69,865,000	$ 38,730,000
2009	876,000	14,940,000	3,366,000	$ 71,863,000	$ 40,434,000

(1) Pursuant to SEC regulations, natural gas is converted to barrels of oil equivalent ("BOE") using the conversion of six Mcf "equivalent" to one barrel of oil.
(2) The percentage of total reserves classified as proved undeveloped was approximately 51% in 2011 and 39% in 2010 and 2009.

Oil reserves represent 48% of the Company's total proved reserves for fiscal 2011 compared to 29% last year, as the Company continues its successful transition from natural gas to oil. For fiscal 2011, oil reserves increased 106% on record capital spending and successful completions in the Company's North Dakota Bakken and Three Forks, Kansas, Nebraska and Texas Panhandle drilling projects. Because no gas wells were drilled in 2011, gas reserves declined 8%, which is considered at the high end of the normal decline range for the Company's gas properties. The increase in oil reserves more than offset the decline in gas reserves and resulted in a 25% increase in total reserves.

The following table breaks out total proved reserves and Bakken proved reserves as of October 31, 2011 between the proved developed and proved undeveloped categories.

	Fiscal Year Ended October 31, 2011					
Proved	Oil (Bbls)		Natural Gas (Mcf)		Total (BOE) (1)	
Category	Bakken (3)	Total	Bakken (3)	Total	Bakken (3)	Total
Developed	174,000	705,000	104,000	7,772,000	192,000	2,000,000
Undeveloped (2)	1,006,000	1,258,000	742,000	5,019,000	1,130,000	2,095,000
Total	1,180,000	1,963,000	846,000	12,791,000	1,322,000	4,095,000

	Fiscal Year Ended October 31, 2010					
Proved	Oil (Bbls)		Natural Gas (Mcf)		Total (BOE) (1)	
Category	Bakken (3)	Total	Bakken (3)	Total	Bakken (3)	Total
Developed	47,000	501,000	22,000	8,971,000	51,000	1,996,000
Undeveloped (2)	169,000	453,000	159,000	4,967,000	196,000	1,281,000
Total	216,000	954,000	181,000	13,938,000	247,000	3,277,000

(1) Pursuant to SEC regulations, natural gas is converted to barrels of oil equivalent ("BOE") using the conversion of six Mcf "equivalent" per one barrel of oil. This conversion is based on energy equivalence and not price equivalence.
(2) The percentage of Bakken reserves included in the Company's proved undeveloped category has increased from 9% in 2009 to 54% in 2011. The percentage of proved undeveloped ("PUD") reserves increased significantly in fiscal 2011 primarily because a significant amount of drilling occurred around the Company's Bakken acreage which proved-up drilling locations on Company's acreage that directly offset new producing wells. The Company expects to drill and develop its proved undeveloped reserves within five years of the date the reserves were initially recorded.
(3) Bakken reserves include reserves for the Bakken and Three Forks formations.

Estimated Future Net Revenues Discounted at 10% is not a GAAP measure of operating performance. Because oil and gas production is generally long lived, this pre-tax, non-GAAP measure is used by the Company primarily to compare returns on alternative investments. The Company believes that this measure may also be useful to investors for the same purpose. The related GAAP measure is known as the Standardized Measure of Discounted Future Net Cash Flows From Reserves. The difference between the two measures is that the GAAP measure includes tax effects while the measure used by the Company does not include tax effects. The Company uses the non-GAAP measure because it does not consider future income taxes to be particularly relevant to its investment decisions. The Company drills new wells on an ongoing basis, and plans to continue to do so in the future. Thus, it expects to continue to generate deferred income taxes which are not reasonably expected to be paid in the near term. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note 12 to the Company's Consolidated Financial Statements.

	Year Ended October 31,		
	2011	2010	2009
Estimated future net revenues discounted at 10%	$ 62,348,000	$38,730,000	$ 40,434,000
Future income tax expense	(23,867,000)	(14,898,000)	(15,119,000)
Effect of the 10% discount factor on future income tax expense	11,616,000	7,098,000	7,285,000
Standardized measure of discounted future net cash flows	$ 50,097,000	$ 30,930,000	$ 32,600,000

Production, Average Sales Prices and Average Production Costs

Refer to the "Product Prices and Production" section of Item 7, MD&A.

Productive Wells and Developed Acreage

Developed acreage at October 31, 2011 totaled 23,000 net and 90,000 gross acres. At October 31, 2011, the Company owned working interests in 80 net (332 gross) wells consisting of 52 net (224 gross) natural gas wells and 28 net (108 gross) oil wells. In addition, the Company owned royalty and production payment interests in approximately 1,200 wells, primarily coal bed methane, located in Wyoming. In 2011, two wells were acquired, and 22 were sold or abandoned.

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,	Working Interest Acreage		Royalty Interest Acreage	
	Gross	Net	Gross	Net
2012	32,800	17,900	-	-
2013	55,700	32,100	-	-
2014	25,500	17,400	-	-
2015	8,500	6,500	-	-
2016	9,900	7,700	-	-
Thereafter	5,700	3,000	3,100	500
Held-By-Production	18,100	4,800	148,100	7,900
Total	156,200	8,940	151,200	8,400

In general "working interests" have operating rights and are burdened by costs of exploration or lease operations, while "royalty interests" are non-operated interests which are not burdened by 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
2011 *	**49**	**25**	**1**	**19**	**4**	**-**	**-**
2010	34	15	4	15	-	-	-
2009	25	7	2	12	1	2	1

* Of the gross wells drilled in 2011, 21, or 43%, were operated by the Company. The remaining wells represent Company participations in wells operated by others. All of the dry holes were located in the Kansas and Nebraska vertical drilling projects where the Company has historically achieved a 40% to 45% success rate. By contrast, the Company has achieved a 100% success rate in its Bakken and Three Forks shale-oil and Texas Panhandle horizontal drilling plays.

Net Wells

Year Ended October 31,	Total Net Wells	Exploratory Oil	Exploratory Gas	Exploratory Dry	Development Oil	Development Gas	Development Dry
2011 *	**20.371**	**10.106**	**0.006**	**9.632**	**0.627**	**-**	**-**
2010	10.572	3.097	1.009	6.466	-	-	-
2009	12.089	3.007	0.131	7.109	0.168	1.230	0.444

* Of the net wells drilled in 2011, 14.2, or 70%, were operated by the Company. The remaining wells represent Company participations in wells operated by others. All of the dry holes were located in the Kansas and Nebraska vertical drilling projects where the Company has historically achieved a 40% to 45% success rate. By contrast, the Company has achieved a 100% success rate in its Bakken and Three Forks shale-oil and Texas Panhandle horizontal drilling plays.

Insurance

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

Facilities and Employees

The Company's corporate headquarters are located at 1801 Broadway, Suite 900, Denver, Colorado, in approximately 5,000 square feet occupied under a lease that expires in April 2016.

As of October 31, 2011, the Company had 15 employees. The Company's employees are 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 including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of 15(d) of the Exchange Act, (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, Environmental Statement 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. The Company was named as a defendant in a lawsuit brought by a former employee. The suit, Pownell v. Credo Petroleum Corp. et al., U.S.D.C. for the District of Colorado, was settled on August 9, 2011 at an incremental cost to the Company, net of amounts previously paid, or accrued, and net of insurance proceeds, of approximately $210,000. The total cost to the Company over the three years of litigation, including legal fees, was approximately $920,000.

ITEM 4. REMOVED AND RESERVED.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

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

	2011		2010	
Quarter Ended	**High**	**Low**	High	Low
January 31	**$ 11.84**	**$ 7.36**	$ 10.52	$ 8.70
April 30	**$ 14.79**	**$ 11.07**	$ 10.47	$ 8.40
July 31	**$ 11.66**	**$ 9.16**	$ 9.91	$ 7.13
October 31	**$ 10.01**	**$ 7.46**	$ 8.63	$ 7.67

At January 4, 2012, the Company had 2,150 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, including stock repurchase programs.

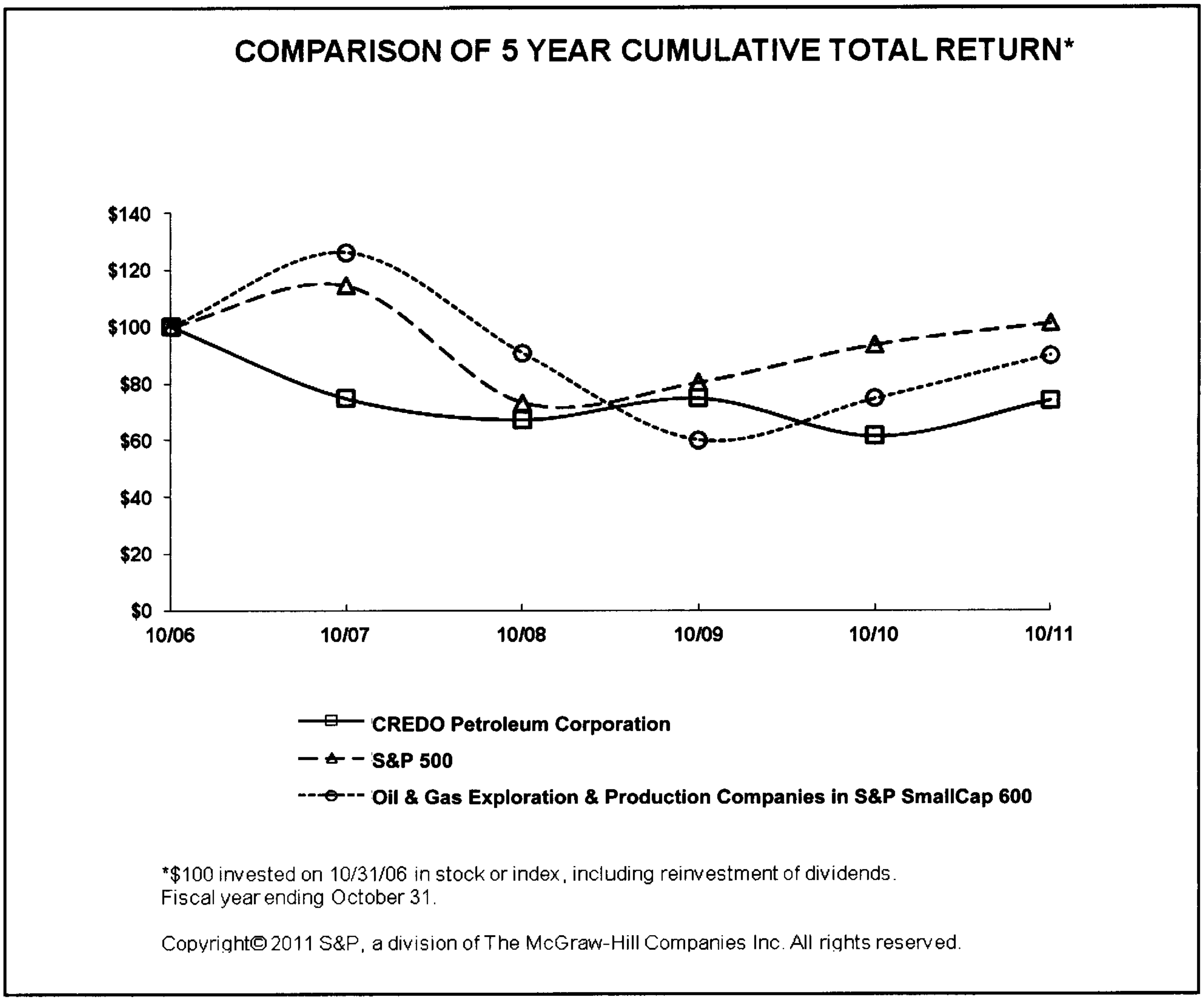
As is shown in the table below, at October 31, 2011, the Company had repurchased 545,429 shares, or 5%, of its common stock at an average price per share of $8.72.

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plan	Maximum dollar value of shares that may yet be purchased under the plan
September 22, 2008 - October 31, 2008	98,940	$ 7.31	98,940	$ 1,277,000
November 1 - 30 2008	45,954	$ 9.45	45,954	$ 843,000
December 1 - 31 2008	22,350	$ 8.88	22,350	$ 645,000
January 1 - 31 2009	6,182	$ 9.16	6,182	$ 588,000
February 1 - 28, 2009 ...	29,104	$ 8.56	29,104	$ 338,000
March 1 - 31, 2009	15,110	$ 7.49	15,110	$ 225,000
April 1 - 30, 2009	12,800	$ 7.76	12,800	$ 2,126,000
June 1 - 30, 2009	1,031	$ 9.58	1,031	$ 2,116,000
July 1 - 31, 2009	6,451	$ 10.90	6,451	$ 2,045,000
August 1-31, 2009	-	$ -	-	$ 2,045,000
September 1-30, 2009	25,412	$ 10.32	25,412	$ 1,783,000
October 1-31, 2009	32,100	$ 10.19	32,100	$ 1,456,000
November 1 - 30, 2009 .	40,937	$ 10.19	40,937	$ 1,039,000
December 1 - 31, 2009 .	-	$ -	-	$ 1,039,000
January 1 - 31, 2010 ..	26,520	$ 9.38	26,520	$ 790,000
February 1 - 28, 2010 .	23,800	$ 8.87	23,800	$ 579,000
March 1-31, 2010	7,800	$ 9.73	7,800	$ 503,000
April 1 - 30, 2010	16,378	$ 9.84	16,378	$ 342,000
May 1 - 30, 2010	18,600	$ 9.24	18,600	$ 170,000
June 1 - 30, 2010	21,167	$ 8.02	21,167	$ -
July 1 - 31, 2010	24,000	$ 7.59	24,000	$ 818,000
August 1 - 31, 2010	13,827	$ 7.87	13,827	$ 709,000
September 1 - 30, 2010 ..	26,566	$ 8.25	26,566	$ 490,000
October 1 - 31, 2010	12,400	$ 8.07	12,400	$ 390,000
November 1 - 31, 2010 ...	18,000	$ 8.04	18,000	$ 245,000
Total	545,429	$ 8.72	545,429	$ 245,000

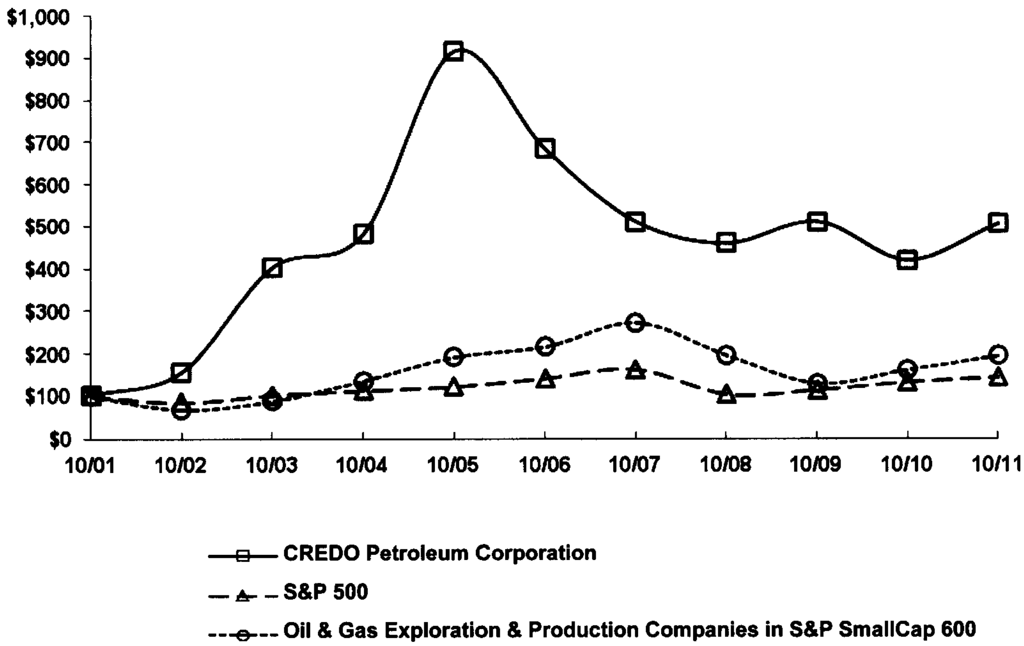
All purchases were made pursuant to a stock repurchase plan announced on September 24, 2008 and extended by the Board of Directors on April 9, 2009 and July 29, 2010. The extended plan authorized repurchases up to $5,000,000, but could be expanded, suspended or discontinued at any time.

Performance Graph

The following performance graphs compare the cumulative total stockholder return on the Company's common stock for the five and ten year periods ended October 31, 2011 with the cumulative total return of the oil and gas exploration and production companies included in the S&P SmallCap 600 Index and the cumulative total return of the Standard & Poor's 500 Stock Index for the same periods.



COMPARISON OF 10 YEAR CUMULATIVE TOTAL RETURN*



*$100 invested on 10/31/01 in stock or index, including reinvestment of dividends.
Fiscal year ending October 31.

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, 2011 were derived from the audited financial statements and the accompanying notes to those financial statements.

	Years Ended October 31,				
	2011	2010	2009	2008	2007
Audited Financial Information					
Statement of Operations Data:					
Oil and gas sales	**$ 16,767,000**	$ 11,566,000	$ 10,067,000	$17,345,000	$ 14,265,000
Oil and gas production expense	**4,000,000**	3,192,000	3,260,000	3,861,000	3,375,000
Depreciation, depletion and amortization	**5,179,000**	3,602,000	4,439,000	3,583,000	3,666,000
Non-cash writedown of oil & gas properties and impairment of long lived assets	**-**	-	24,653,000	-	-
General and administrative .	**2,675,000**	2,107,000	3,250,000	1,637,000	1,397,000
Income(loss) from operations	**4,913,000**	2,665,000	(25,535,000)	8,264,000	5,827,000
Realized and Unrealized gains(losses) from derivative contracts	**(183,000)**	42,000	2,079,000	188,000	1,455,000
Income(loss) before income taxes	**4,788,000**	2,815,000	(23,515,000)	8,153,000	8,075,000
Net income(loss)	**3,518,000**	2,203,000	(14,454,000)	5,993,000	5,760,000
Earnings(loss) per share:					
Basic	**$ 0.35**	$ 0.22	$ (1.40)	$ 0.62	$ 0.62
Diluted	**$ 0.35**	$ 0.22	$ (1.40)	$ 0.61	$ 0.61
Weighted-average shares outstanding:					
Basic	**10,042,000**	10,183,000	10,326,000	9,697,000	9,280,000
Diluted	**10,074,000**	10,202,000	10,326,000	9,758,000	9,395,000
Balance Sheet Data:					
Working capital	**2,940,000**	9,661,000	13,542,000	24,160,000	12,511,000
Total assets	**61,036,000**	53,405,000	52,552,000	80,650,000	55,349,000
Long-term obligations:					
Deferred income taxes-net .	**4,505,000**	3,281,000	2,537,000	11,117,000	9,204,000
Asset retirement obligation	**1,213,000**	1,132,000	1,502,000	1,338,000	1,016,000
Exclusive license agreement obligation	-	-	-	-	85,000
Stockholders' equity	**50,001,000**	46,567,000	46,056,000	62,211,000	41,140,000
Unaudited Operating Data					
Production Volumes:					
Oil (Bbls)	**148,000**	97,000	116,000	56,000	51,000
Gas (Mcf)	**918,000**	1,038,000	1,229,000	1,545,000	1,926,000
BOE	**301,000**	270,000	321,000	314,000	372,000
Avg. sales price before realized derivative gains & losses:					
Per Bbls	**$ 85.16**	$ 70.88	$ 51.46	$ 99.28	$ 60.95
Per Mcf	**$ 4.54**	$ 4.54	$ 3.35	$ 7.65	$ 5.79
Reserves[(1)]					
Oil (Bbls)	**1,963,000**	954,000	876,000	710,000	591,000
Gas (Mcf)	**12,791,000**	13,938,000	14,940,000	15,525,000	16,973,000
BOE	**4,095,000**	3,277,000	3,366,000	3,297,000	3,420,000
Estimated future net revenues	**$ 116,317,000**	$ 69,865,000	$ 71,863,000	$53,655,000	$ 101,501,000
Estimated future net revenues discounted at 10%	**$ 62,348,000**	$ 38,730,000	$ 40,434,000	$32,330,000	$ 62,071,000

(1) See Footnote 13 to the Consolidated Financial Statements.

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

Operations

Summary -- During 2010 and 2011, the Company's operations focused on drilling for oil in the North Dakota Bakken and Three Forks shale-oil play as well as Kansas, Nebraska, and the Texas Panhandle. The Company's drilling activities are discussed in greater detail below.

The Company believes that its geographically and technically diverse oil drilling projects provide an excellent balance for achieving its goal of adding oil reserves and production at reasonable costs and risks. The Company expects its horizontal drilling results to occur relatively evenly due to the more developmental nature of the drilling. The Company expects its vertical drilling results will occur less evenly due to the more exploratory nature of the projects.

In fiscal 2012, the Company will continue to focus on drilling for oil reserves and expects these activities to be a reliable source of oil production and reserve additions. However, the timing and extent of such activities can be dependent on many factors which are beyond the Company's control, including for non-operated properties, the timing decisions of the well "operators" related to drilling, the availability of oil field services such as drilling rigs, fracture stimulation equipment and related services, and particularly in North Dakota, the weather. The price of oil and natural gas has a significant effect on the demand for, and cost of, drilling and oil field services.

Certain Significant Effects of the Company's Strategic Transition to Oil from Natural Gas
In recent years, the Company has made significant strategic changes with the objective of transitioning its production and reserves from virtually all natural gas to being primarily oil. This strategic decision was made because the Company believes that oil will continue to maintain a significant Btu price premium over U.S. sourced natural gas. To accomplish this objective, the Company implemented new conventional exploration projects in Kansas and Nebraska, and new horizontal exploration projects in the North Dakota Bakken and Three Forks shale-oil play and the Texas Panhandle. These strategic changes are also intended to diversify the Company's drilling projects both geographically and scientifically. In 2011, the Board approved a record $15.5 million oil-focused drilling budget which was nearly double the Company's prior year drilling budget. The following table shows the success to date of the transition to oil as proved oil reserves have steadily increased to 48% of total reserves in fiscal 2011 from only 17% in 2007. More importantly, due to the significant Btu price premium of oil over natural gas at October 31, 2011, the undiscounted value of proved oil reserves was approximately 75% of total reserve value.

Fiscal Year Ended	Oil Reserves (Bbls)	YOY Percentage Change	Oil as % of Total Reserves
2007	591,000	40%	17%
2008	710,000	20%	21%
2009	876,000	23%	26%
2010	954,000	9%	29%
2011	**1,963,000**	**106%**	**48%**

In the fourth quarter of 2011, a significant transition milestone was achieved when oil production represented 56% of total production quantities and the Company became primarily an oil producer for the first time in its history. Due to the Btu value difference between oil and natural gas, oil represented about 80% of fourth quarter revenues.

This transition has significantly altered the components of the Company's proved reserves, production, revenues and capital requirements. In particular, the economic and reserve characteristics of the Bakken and Three Forks drilling project are substantially different from any drilling project in which the Company has previously participated. Among other things, this has resulted in significant changes in the make-up of the Company's reserves, its capital expenditures and its financing requirements.

In fiscal 2011, proved undeveloped ("PUD") reserves increased to a historic high. The Company's acreage in the North Dakota Bakken and Three Forks shale-oil play has added significant oil reserves. The large percentage increase in reserves in fiscal 2011 occurred primarily because a significant amount of drilling occurred around the Company's Bakken acreage which proved-up drilling locations on the Company's acreage that directly offset new producing wells. At October 31, 2011, the Company's PUD reserves comprised 51% of total proved reserves, 60% of which are Bakken and Three Forks PUD reserves. Refer to the "Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues" section of Item 2, Properties, and Note 13 to the Consolidated Financial Statements for additional reserve information.

The cost per BOE of Bakken and Three Forks reserves is considerably higher than the Company's historical cost per BOE of properties being amortized. For fiscal 2011, DD&A per BOE increased 35% to $15.62, primarily because the cost of Bakken and Three Forks reserve additions (both developed and undeveloped) per BOE are higher than the cost per BOE of the Company's historical reserves. Going forward, the Company expects Bakken and Three Forks wells to represent an increasingly large percentage of the cost of properties being amortized. Accordingly, the Company expects DD&A per BOE to continue to increase. Refer to the "Results of Operations" section of MD&A for additional information.

The significant increase in Bakken and Three Forks PUD reserves in fiscal 2011 was accompanied by a significant increase in the cost to develop those reserves. Under the full cost accounting method followed by the Company, PUD reserves and their future development costs must be included in the calculation of DD&A. Seventy three percent (73%) of future development costs at October 31, 2011 are for Bakken and Three Forks development wells. As discussed above, the inclusion of such costs in the DD&A calculation causes DD&A to increase, however, for PUD reserves there are no offsetting revenues until the reserves are actually developed and placed on production. Accordingly, Bakken and Three Forks PUD reserves had a negative effect on fiscal 2011 net income. In future years, any year over year increase in Bakken and Three Forks PUD reserves will have a negative effect on net income until the reserves are developed and placed on production.

Drilling expenditures are expected to almost double in fiscal 2012 and, for the first time in the Company's history, financing is expected to be required to fund a portion of future drilling expenditures. The Company has approved a drilling expenditure budget of $30,000,000 for fiscal 2012 which is about double last year's drilling budget. Two thirds of the 2012 drilling budget is earmarked for drilling in the Bakken and Three Forks play. To provide adequate capital to continue the accelerated drilling programs, subsequent to fiscal 2011 year end, the Company has entered into an oil and gas reserves borrowing base revolving credit line with its principal bank. The initial borrowing base will be $7 million but may be extended twice a year. Borrowing in 2012 is expected to range from $7 million to $12 million. The financing agreement is pending final execution of the paperwork. In future years, the Company reasonably expects that additional financing, either debt or equity, will be required. See additional information below regarding uncertainties related to the timing and costs of Bakken and Three Forks drilling due to the Company being a non-operator, and additional information below regarding projected capital expenditures and capital requirements. See Note 6 to the Consolidated Financial Statements for further information regarding debt financing.

A portion of the Company's estimated oil production for fiscal 2012 has been hedged to assure a certain level of cash flow for debt service. The Company has entered into hedging contracts covering between 15% and 25% its estimated fiscal 2012 oil production. See Note 5 to the Consolidated Financial Statements for further information regarding hedging transactions.

The Company is not the "operator" for its Bakken and Three Forks acreage and is, therefore, not in control of the timing of drilling or the amount of expenditures. Larger companies with more experience drilling and operating Bakken and Three Forks wells are the "operators" of the spacing units which include the Company's leases because such companies generally own a majority (or very large) interest in the spacing units. The primary advantages to the Company are as follows: (i) larger companies have much larger staffs than the Company which include people who specialize in many of the individual technical aspects of horizontal Bakken and Three Forks drilling and operations, and (ii) larger companies generally operate many wells in the Bakken and Three Forks play and thus have the ability to compete for oil field services and product markets more effectively than the Company. The primary disadvantage of the Company being a non-operator in the

Bakken and Three Forks play is that the Company is not in control of timing of drilling operations or the costs of drilling and operating the wells.

Because the Company is not in control of the timing of drilling operations in the Bakken and Three Forks play, it cannot reasonably predict the timing and extent of drilling costs until the operators actually propose wells. Accordingly, the Company's fiscal 2012 drilling budget attempts to estimate drilling schedules through discussions with operators before wells are actually proposed. As a result, the Company's fiscal 2012 drilling schedule and drilling budget are subject to significant revision as more information becomes available during the year regarding the actual timing and costs of drilling. In general, the Company expects its Bakken and Three Forks drilling to rapidly accelerate in fiscal 2012 and 2013 as the operators proactively drill their leases within the primary terms of the leases. There may be a further drilling push related to development of the Three Forks formation if operators conclude that, for technical reasons, the Three Forks formation should be drilled before substantial depletion occurs in the Bakken formation. As previously noted, the Company expects financing to be required for its current fiscal 2012 drilling budget, and it is reasonable to expect that additional financing will be required in future years. However, the amounts and timing of such financing requirements cannot be reasonably predicted.

Results of Operations

In 2011, oil and gas revenues increased 45% to $16,767,000 compared to $11,566,000 in 2010. Total production, at the six Mcf of gas to one barrel of oil energy equivalent ratio, increased 12% to 301,000 barrels of oil equivalent (BOE). The increased production resulted in a revenue increase of $3,819,000. As the oil and gas price/volume table on page 26 shows, oil prices increased to $85.16 per barrel and natural gas sales prices remained unchanged. The net effect of the price change was to increase total oil and gas sales by $1,382,000. Realized derivative losses were $191,000 in 2011 compared to a gain of $115,000 in 2010. Unrealized derivative gains were $8,000 in 2011 compared to unrealized losses of $73,000 in 2010. Investment and other income decreased due to the impact of market place volatility on the Company's investments.

In 2011, total costs and expenses increased 33% to $11,854,000 compared to $8,901,000 in 2010. Oil and gas production expenses increased 25% primarily due to production taxes on increased revenue together with the increased number of operating wells. DD&A increased primarily due to an increase in the amortizable base including future development costs related to proved undeveloped oil reserves in the Bakken. (Refer to the "Certain Significant Effects of the Company's Strategic Transition to Oil from Natural Gas" section of MD&A for further information regarding DD&A changes.) General and administrative expenses increased due primarily to legal and professional fees and the settlement of a lawsuit. The effective income tax rate was 26% and 22% for the 2011 and 2010 periods, respectively. The variation from the statutory rate in 2011 is primarily due to the effect of percentage depletion.

In 2010, oil and gas revenues increased 15% to $11,566,000 compared to $10,067,000 in 2009. The increase was due to a 38% increase in oil prices and a 37% increase in natural gas prices. As the oil and gas price/volume table on page 26 shows, oil prices increased to $70.88 per barrel and natural gas sales prices increased to $4.54 per Mcf. The net effect of these price changes was to increase total oil and gas sales by $3,710,000. Realized derivative gains were $115,000 in 2010 compared to $3,720,000 in 2009. Unrealized derivative losses were $73,000 in 2010 compared to unrealized losses of $1,641,000 in 2009. During the same period, the Company's total production decreased 16% to 270,000 BOE, resulting in a decrease in oil and gas sales of $2,211,000. The decline in 2010 oil production resulted because of delays caused by shortages of fracture stimulation equipment for horizontal wells in the North Dakota Bakken and the Texas Panhandle. The situation was exacerbated by the expected flush production decline on the Huslig Field discovery which peaked last year at about 365 barrels of oil per day, net to Credo. In addition, the Company did not drill any gas wells during 2010 due to low natural gas prices. Investment and other income increased primarily due to the impact of market place improvements on the Company's investments.

In 2010, total costs and expenses, excluding the impairment loss of $24,653,000 in 2009, decreased 19% to $8,901,000 compared to $10,949,000 in 2009. Oil and gas production expenses decreased 2% due primarily to decreased field level service costs. General and administrative expenses decreased $1,143,000 to $2,107,000 primarily due to decreased salaries and benefits and lower legal and professional fees. The effective income tax rate was 22% and 38.5% for the 2010 and 2009 periods, respectively. The variation from the statutory rate in 2010 is primarily due to percentage depletion.

Liquidity and Capital Resources

For the year ended October 31, 2011, net cash provided by operating activities was $10,803,000 compared to $4,533,000 for 2010. Net cash used in investing activities was $14,524,000 and $7,932,000 for the years ended October 31, 2011 and 2010 respectively. Net cash used in investing activities is exclusive of expenditures included in current liabilities of $3,058,000 and $954,000 at October 31, 2011 and 2010 respectively. Investing activities primarily included oil and gas lease acquisition, exploration and development expenditures.

In 2011 the Company executed the most aggressive drilling program in its history, expending approximately $15.5 million. As a result, cash and short term investments are being rapidly utilized as expected and budgeted, and working capital declined from $9,661,000 at October 31, 2010 to $2,940,000 at October 31, 2011. Refer to the "Certain Significant Effects of the Company's Strategic Transition to Oil from Natural Gas" section of MD&A for anticipated drilling expenditures and financing requirements. Because earnings are anticipated to be reinvested in operations, cash dividends are not expected to be paid. The Company has no defined benefit plans and no obligations for post retirement employee benefits.

The Company's earnings before interest, taxes, depreciation, depletion and amortization and write-downs of oil and gas properties and impairment losses ("EBITDA") was $9,967,000 for the year ended October 31, 2011 and $6,417,000 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:

RECONCILIATION OF EBITDA:	For The Year Ended October 31, 2011	2010	2009
Net Income (Loss)	**$ 3,518,000**	$ 2,203,000	$ (14,454,000)
Add Back (Deduct):			
Interest Expense	-	-	3,000
Income Tax Expense (Benefit)	**1,270,000**	612,000	(9,061,000)
Depreciation, Depletion and Amortization Expense	**5,179,000**	3,602,000	4,439,000
Write-Down of oil and natural gas properties and impairment of intangible assets	-	-	24,653,000
EBITDA	**$ 9,967,000**	$ 6,417,000	$ 5,580,000

As of October 31, 2011, 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
Operating lease obligations	205,000	46,000	91,000	68,000	-
Total	$ 205,000	$ 46,000	$ 91,000	$ 68,000	$ -

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements at October 31, 2011.

Product Prices and Production

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

Oil and natural gas sales volume and price realization comparisons for the years ended October 31, 2011, 2010 and 2009 are set forth below. Prices shown are market price and do not include realized hedging gains and losses.

	Twelve Months Ended October 31,					
	2011 Wellhead		2010 Wellhead		2009 Wellhead	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Oil (bbls)	**148,000**	**$ 85.16**	97,000	$ 70.88	116,000	$ 51.46
Gas (Mcf)	**918,000**	**$ 4.54**	1,038,000	$ 4.54	1,229,000	$ 3.35
BOE(1)	**301,000**		270,000		320,000	

(1) Pursuant to SEC regulations, natural gas is converted to barrels of oil equivalent ("BOE") using the energy equivalent conversion of six Mcf "equivalent" to one barrel of oil.

The effect of realized derivative gains and losses on wellhead price realizations are reflected in the following table:

	Twelve Months Ended October 31,								
	2011			2010			2009		
Product	**Net Wellhead Price**	**Realized Derivative (Loss)**	**Effective Price Realization**	Net Wellhead Price	Realized Derivative Gain	Effective Price Realization	Net Wellhead Price	Realized Derivative Gain	Effective Price Realization
Oil ...	**$ 85.16**	**$ (1.16)**	**$ 84.00**	$ 70.88	$ -	$ 70.88	$ 51.46	$ -	$ 51.46
Gas ...	**$ 4.54**	**$ (0.02)**	**$ 4.52**	$ 4.54	$ 0.11	$ 4.65	$ 3.35	$ 3.02	$ 6.37

Average production costs, including production taxes, per equivalent BOE of production (using the energy equivalent conversion of six Mcf of gas to one barrel of oil) were $13.29, $11.84 and $10.17 per BOE in 2011, 2010 and 2009 respectively. Depreciation, depletion and amortization per equivalent BOE for the same periods were $15.62, $11.60 and $12.27. The future development costs for Bakken and Three Forks PUD reserves added in fiscal 2011 caused the substantial increase in DD&A. Refer to the "Certain Significant Effects of the Company's Strategic Transition to Oil from Natural Gas" section of MD&A for more information regarding the increase in DD&A per equivalent BOE.

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 production when the potential for significant downward price movement is anticipated, or to assure availability of a portion of the cash flow for anticipated debt service. Such hedges are authorized by the Company's Board of Directors and they do not exceed estimated production volumes for the periods hedged. Hedging transactions may take the form of costless collars or forward short positions and are generally based on the NYMEX futures prices at the time the transactions are initiated. The positions are normally closed by purchasing offsetting positions. Contracts 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 has elected not to designate its commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on its Balance Sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

At October 31, 2011 the Company held open short derivative contracts for 6,000 barrels per month covering the production months of January through December 2012 at prices ranging from $91.95 to

$93.00. This hedge is expected to cover 15% to 25% of the Company's estimated oil production for fiscal 2012. The Company held no open derivative contracts for natural gas.

The Company has a derivative 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 available is $7,200,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the Company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the Company's bank, and prohibits funded debt in excess of $500,000. The line expires May 1, 2013. The credit line has been incorporated into the revolving credit agreement entered into subsequent to October 31, 2011. See Footnote 6 to the Consolidated Financial Statements for further discussion of the credit line.

Oil and Gas Activities

Capital Spending. Capital spending in 2011 totaled $16,732,000 including $15,500,000 related to the Company's drilling budget. Refer to the "Certain Significant Effects of the Company's Strategic Transition from Natural Gas to Oil" section of MD&A for additional information regarding 2011 and projected 2012 drilling expenditures.

Drilling Activities

See Item 1. for a general discussion of the Company's business. See Item 2. for a discussion of the Company's properties.

As discussed in Item 1. "Business", since 2008, the Company's business strategy has focused primarily on drilling for oil in the North Dakota Bakken and Three Forks shale-oil play and in Kansas, Nebraska and the Texas Panhandle.

In North Dakota's Bakken and Three Forks shale-oil play, the Company participated in 8 gross (0.4 net) Bakken wells during 2011 with an average 5% working interest. To date, the Company has participated in 11 gross (0.8 net) Bakken wells with an average 7% working interest. All of the Company's Bakken wells have been successfully completed as high rate producers with initial rates ranging from 769 to 3,732 BOE per day. The Company owns interests in sixty two (62) spacing units with interests ranging from very small to 23%. The Company's average working interest in the 62 spacing units is approximately 8%, assuming all spacing units contain 1,280 acres. To date, 11 of the spacing units have been successfully tested by an initial Bakken well. The Company currently estimates that 23 gross (2.7 net) Bakken and Three Forks wells will be drilled on its acreage during 2012. The Company believes it is likely that more than one well will be drilled on the vast majority of its spacing units. Bakken and Three Forks wells on 1,280 acre spacing units generally have a measured depth of about 20,000 feet, consisting of 10,000 feet vertical and 10,000 feet horizontal. Wells currently cost about $10,000,000. Due to the high cost of drilling and operating Bakken and Three Forks wells, their economics are highly dependent on oil prices. The Company estimates that it needs to realize wellhead oil prices ranging between $70.00 and $90.00 per BOE in order to achieve its desired economic objectives. All of the Company's Bakken and Three Forks spacing units are operated by larger companies which, thus far, have had the ability to obtain field services on a timely basis and at competitive prices. See Item 1A. "Risk Factors".

In Kansas and Nebraska, the Company is conducting primarily a wildcat oil drilling project using the combination of subsurface geology which is generally confirmed by 3-D seismic. During 2011, the Company participated in 36 gross (19.2 net) wells with an average 53% working interest. To date, the Company has participated in 107 gross (44 net) wells with an average 42% working interest. The Company's overall drilling success rate is about 42%, which the Company believes is approximately the same success rate as other knowledgeable companies involved in the area. For 2012, the Company estimates that it will participate in 52 gross (29 net) wells in Kansas and Nebraska with an average working interest of approximately 56%. Wells are drilled to a vertical depth of 4,000 to 5,000 feet, and completed well cost is approximately $450,000. The Company estimates that it can achieve its minimum drilling economics at oil prices as low as $50.00. The Company will be the operator of approximately 65% of the wells expected to be drilled in 2012.

In the Texas Panhandle, the Company is conducting two horizontal drilling projects and one vertical drilling project. The Tonkawa and Cleveland formations are being developed by horizontal drilling. Horizontal wells are drilled on 320 or 640 acre spacing units and generally have a measured depth of about 14,000 feet, consisting of 9,000 feet vertical and 5,000 feet horizontal. Wells currently cost about $4,400,000. The Company owns interests in four 640 acre spacing units that are prospective for Tonkawa and Cleveland horizontal drilling and believes that each spacing unit could ultimately contain two Tonkawa and two Cleveland wells. In addition, the Company has drilled one vertical Tonkawa well and one vertical Morrow well on its acreage with an average working interest of 28%. It is anticipated that two or more additional Morrow wells will be drilled on the acreage when natural gas prices improve. Morrow wells are drilled to an approximate depth of 11,000 feet and cost approximately $4,000,000.

Natural gas drilling in Oklahoma has been suspended pending a recovery in natural gas prices. Accordingly, no gas wells were drilled in Oklahoma during 2011. Most of the Company's Oklahoma acreage is held by production and, thus, the timing of drilling is not critical to maintaining the Company's leasehold ownership.

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.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires the Company to make certain estimates and assumptions that affect the reported amounts of assets, liabilities and reserves 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 current information and historical experience as well as 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. 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.

Derivatives. The Company has elected not to designate its commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on its balance sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

Oil and Gas Properties.
The Company uses the full cost method of accounting for costs related to its oil and natural gas properties. Capitalized, evaluated, costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. Costs for unevaluated properties, which typically include lease rentals, geology and seismic costs, are capitalized but are excluded from amortizable costs during the evaluation period. When determinations are made whether the property has proved recoverable reserves or not, or if there is an impairment, the costs are reclassified to amortizable costs.

The Company performs a ceiling test each quarter. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices (discussed below), excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, at a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. The current prices utilized are based on the average of the first-day-of-the-month prices during the preceding twelve-month period pursuant to the SEC's "Modernization of Oil and Gas Reporting" rule. For fiscal year 2011, the average of the first-day-of-the-month oil price was $86.32 per barrel, and the average of the first-day-of-the-month gas price was $4.54 per Mcf.

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 the average prices in effect as of the first day of each month 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 average prices and costs in effect during the preceding year.

Oil and Gas Reserves. The determination of depreciation and depletion expense as well as the ceiling test 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. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the Company's control. 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.

As more information becomes available, it is reasonable to expect actual future production, oil and natural gas prices, revenues, taxes, development expenditures , operating expenses and quantities of recoverable oil and natural gas reserves will vary from the estimates, including the timing of expenditures and revenue receipts. Accordingly, reserve quantity estimates are often different from the quantities of oil and natural gas ultimately recovered and the corresponding production and development costs associated with the recovery of these reserves are often different than the estimated costs. Any significant variance could materially affect the estimated quantities and the present value of reserves disclosed by the Company. Reserve estimates and valuations will be adjusted in the future as more information becomes available. In addition, the Company's Calliope System is generally installed on mature wells. As such, they contain older down-hole equipment, such as casing, that is more subject to failure than new equipment. The failure of such equipment can result in complete loss of a well. Historically, such data and equipment failures have not caused significant revisions in the Company's total proved reserve quantities.

One measure of the life of the Company's proved reserves can be calculated by dividing proved reserves at fiscal year end 2011 by production for fiscal year 2011. This measure yields an average reserve life of 13.6 years. Since this measure is an average based on both producing and non-producing reserves, 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.

Intangible Assets. The patents underlying the Calliope Gas Recovery System are carried as a non-current asset on the Company's balance sheet and are being amortized over the average remaining life of the patents. The Company periodically evaluates this asset to evaluate whether the remaining value is recoverable.

Asset Retirement Obligations. The FASB authoritative guidance 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, 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(See Item 1A, Risk Factors, for further information regarding Market Risk)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements Page

CONSOLIDATED BALANCE SHEETS
October 31, 2011 and 2010

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

ASSETS	2011	2010
Current assets:		
Cash and cash equivalents	$ 3,313,000	$ 7,179,000
Short-term investments	1,487,000	1,990,000
Receivables:		
Trade	893,000	479,000
Accrued oil and gas sales	2,343,000	1,574,000
Derivative assets	8,000	32,000
Other current assets	213,000	832,000
Total current assets	8,257,000	12,086,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	9,609,000	8,801,000
Evaluated oil and gas properties	99,283,000	83,360,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	(61,042,000)	(56,339,000)
Net oil and gas properties	47,850,000	35,822,000
Intangible assets, net of accumulated amortization of $1,307,000 in 2011 and $872,000 in 2010	3,142,000	3,578,000
Compressor and tubular inventory to be used in development of oil and gas properties	1,690,000	1,855,000
Other, net	97,000	64,000
Total assets	$ 61,036,000	$ 53,405,000

LIABILITIES AND STOCKHOLDERS' EQUITY	2011	2010
Current liabilities:		
Accounts payable	$ 3,665,000	$ 1,200,000
Revenue distribution payable	964,000	565,000
Accrued compensation	246,000	466,000
Other accrued liabilities	337,000	177,000
Income taxes payable	105,000	17,000
Total current liabilities	5,317,000	2,425,000
Long-term liabilities:		
Deferred income taxes, net	4,505,000	3,281,000
Asset retirement obligation	1,213,000	1,132,000
Total liabilities	11,035,000	6,838,000
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, 10,660,000 shares issued	1,066,000	1,066,000
Capital in excess of par value	31,547,000	31,486,000
Treasury stock, at cost, 619,000 shares in 2011, and 601,000 shares in 2010	(4,654,000)	(4,509,000)
Retained earnings	22,042,000	18,524,000
Total stockholders' equity	50,001,000	46,567,000
Total liabilities and stockholders' equity	$ 61,036,000	$ 53,405,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three Years Ended October 31, 2011

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2011	2010	2009
Oil sales	**$ 12,599,000**	$ 6,855,000	$ 5,953,000
Gas sales	**4,168,000**	4,711,000	4,114,000
	16,767,000	11,566,000	10,067,000
Costs and expenses:			
Oil and gas production	**4,000,000**	3,192,000	3,260,000
Depreciation, depletion and amortization	**5,179,000**	3,602,000	4,439,000
Write-down of oil and natural gas properties and impairment of long lived assets	**-**	-	24,653,000
General and administrative	**2,675,000**	2,107,000	3,250,000
	11,854,000	8,901,000	35,602,000
Income(loss) from operations	**4,913,000**	2,665,000	(25,535,000)
Other income and (expense)			
Realized and Unrealized gains (losses) from derivative contracts	**(183,000)**	42,000	2,079,000
Investment and other income (loss)	**58,000**	108,000	(59,000)
	(125,000)	150,000	2,020,000
Income(loss) before income taxes	**4,788,000**	(2,815,000)	(23,515,000)
Income taxes	**(1,270,000)**	(612,000)	9,061,000
Net income(loss)	**$ 3,518,000**	$ 2,203,000	$ (14,454,000)
Earnings(loss) per share of Common Stock-Basic	**$ 0.35**	$ 0.22	$ (1.40)
Earnings(loss) per share of Common Stock-Diluted	**$ 0.35**	$ 0.22	$ (1.40)
Weighted average number of shares of common stock and dilutive securities:			
Basic	**10,042,000**	10,183,000	10,326,000
Diluted	**10,074,000**	10,202,000	10,326,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Three Years Ended October 31, 2011

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock		Capital In Excess Of Par Value	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
Balance, October 31, 2008	10,660,000	1,066,000	31,352,000	(982,000)	30,775,000	62,211,000
Comprehensive income(loss):						
Net (loss)	-	-	-	-	(14,454,000)	(14,454,000)
Purchase of treasury stock	-	-		(1,821,000)	-	(1,821,000)
Compensation expense related to stock options	-	-	31,000	-	-	31,000
Tax benefit from exercise of stock options	-	-	89,000	-	-	89,000
Balance, October 31, 2009	10,660,000	1,066,000	31,472,000	(2,803,000)	16,321,000	46,056,000
Comprehensive income(loss):						
Net income	-	-	-	-	2,203,000	2,203,000
Purchase of treasury stock	-	-		(2,066,000)	-	(2,066,000)
Compensation expense related to stock options	-	-	78,000	-	-	78,000
Exercise of stock options	-	-	(64,000)	360,000	-	296,000
Balance, October 31, 2010	10,660,000	$1,066,000	$31,486,000	$(4,509,000)	$18,524,000	$46,567,000
Comprehensive income(loss):						
Net income	-	-	-	-	3,518,000	3,518,000
Purchase of treasury stock	-	-		(145,000)	-	(145,000)
Compensation expense related to stock options	-	-	61,000	-	-	61,000
Balance, October 31, 2011	10,660,000	$1,066,000	$31,547,000	$(4,654,000)	$22,042,000	$50,001,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Years Ended October 31, 2011

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2011	2010	2009
Cash flows from operating activities:			
Net income(loss)	**$ 3,518,000**	$ 2,203,000	$(14,454,000)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Non-cash write-down of oil and natural gas properties and impairment of long lived assets	**-**	-	24,653,000
Depreciation, depletion and amortization	**5,179,000**	3,602,000	4,439,000
ARO liability accretion	**70,000**	75,000	77,000
Unrealized (gains) losses from derivatives	**24,000**	72,000	1,641,000
Deferred income taxes	**1,224,000**	744,000	(8,580,000)
(Gain)loss on short-term investments	**(49,000)**	(65,000)	180,000
Compensation expense related to stock options granted	**61,000**	78,000	31,000
Other	-	(1,000)	-
Changes in operating assets and liabilities:			
Proceeds from short-term investments	**602,000**	210,000	2,229,00
Purchase of short-term investments	**(50,000)**	(1,500,000)	-
Trade receivables	**(414,000)**	8,000	508,000
Accrued oil and gas sales	**(769,000)**	(8,000)	167,000
Other current assets	**619,000**	27,000	(654,000)
Accounts payable and accrued liabilities	**700,000**	(874,000)	(236,000)
Income taxes payable	**88,000**	(38,000)	(69,000)
Net cash provided by operating activities	**10,803,000**	4,533,000	9,932,000
Cash flows from investing activities:			
Additions to oil and gas properties	**(15,154,000)**	(8,525,000)	(13,719,000)
Proceeds from sale of oil and gas properties	**703,000**	299,000	-
Changes in other long-term assets	**(73,000)**	294,000	(65,000)
Purchase of intangible assets	**-**	-	(4,400,000)
Net cash used in investing activities	**(14,524,000)**	(7,932,000)	(18,184,000)
Cash flows from financing activities:			
Proceeds and the benefit from exercise of stock options	**-**	296,000	89,000
Purchase of treasury stock	**(145,000)**	(2,066,000)	(1,821,000)
Net cash (used) by financing activities	**(145,000)**	(1,770,000)	(1,732,000)
Increase (decrease) in cash and cash equivalents	**(3,866,000)**	(5,169,000)	(9,984,000)
Cash and cash equivalents:			
Beginning of year	**7,179,000**	12,348,000	22,332,000
End of year	**$ 3,313,000**	$ 7,179,000	$ 12,348,000
Supplemental Cash Flow Information:			
Cash paid during the period for income taxes	**$ -**	$ -	$ -
Additions to oil & gas properties included in current liabilities	**$ 3,058,000**	$ 954,000	$ 74,000

See accompanying notes to consolidated financial statements.

(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. All significant intercompany transactions have been eliminated. All references to years in these Notes refer to the Company's fiscal October 31 year.

Cash, Cash Equivalents, and Short-Term Investments

Cash equivalents consist of liquid investments with original maturities of three months or less. During 2009 the Company liquidated the majority of its short term investments in professionally managed limited partnerships. Other short term investments are directly invested in certificates of deposit and mutual funds. 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. In the event that any individual monthly joint interest receivable becomes delinquent, the Company has the ability to net the receivables against revenue distributions, if any, to the delinquent account. To date the Company has had minimal bad debts.

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, short term investments, 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 crude oil and natural gas. 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 typically 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, or when better information is available.

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, and the estimate of its asset retirement obligation.

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, which are evaluated and 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 or production rates 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.

Oil and Gas Reserves

The determination of depreciation and depletion expense as well as the ceiling test related to the recorded value of the Company's oil and natural gas properties are highly dependent on proved reserve estimates. Proved oil and natural gas reserves include 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. In addition, the value of reserve estimates is often different from the values ultimately recovered due to many factors including product price differences and operating and development cost differences.

Effective October 31, 2010, Credo adopted revised oil and gas disclosure requirements set forth by the U.S. Securities and Exchange Commission (SEC) in Release No. 33-8995, "Modernization of Oil and Gas Reporting" and as codified by the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) Topic 932, "Extractive Industries – Oil and Gas." The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures. Pursuant to SEC regulations, natural gas is converted to barrels of oil equivalent ("BOE") using the energy equivalent conversion of six Mcf "equivalent" to one barrel of oil. See Note 13 for further discussion of reserve estimates and the related uncertainties.

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 in the full cost pool and liability in its Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, 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, 2011	October 31, 2010
Beginning asset retirement obligation	$ 1,132,000	$ 1,502,000
Accretion expense..................................	70,000	75,000
Obligations incurred................................	35,000	27,000
Obligations settled (primarily from sale of assets)....	(7,000)	(373,000)
Change in estimate..................................	(17,000)	(99,000)
Ending asset retirement obligation	$ 1,213,000	$ 1,132,000

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 FASB issued authoritative guidance to long-lived assets not included in oil and gas properties. Under the guidance, 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.

The patents underlying the Calliope Gas Recovery System are carried as a non-current asset on the Company's balance sheet and are being amortized over the average remaining life of the patents. The Company periodically evaluates this asset for realizability.

The Company believes that the number of future installations will be sufficient to demonstrate recoverability of the cost. During 2011, the Company completed two Calliope installations. An additional well is currently schedule for Calliope installation during 2012. If the Company is unable to achieve the expected level of installations, the Company may in the future be required to record an impairment of the asset. Should this event occur, it would be a non-cash charge to income and would have no effect on working capital.

Income Taxes

The Company accounts for income taxes in accordance with FASB issued authoritative guidance 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.

Oil and Natural Gas Derivatives

The Company manages exposure to commodity price fluctuations by periodically hedging a portion of estimated production when the potential for significant downward price movement is anticipated or to assure availability of cash flow for anticipated debt service. These transactions typically take the form of costless collars or forward short positions which are generally based upon the NYMEX futures prices. Hedge contracts are closed by purchasing offsetting positions. Such hedges are authorized by the Company's Board of Directors and do not exceed estimated production volumes for the months hedged. Contracts 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 has elected not to designate its commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on its Balance Sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

Stock-Based Compensation

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

Per Share Amounts

Basic earnings (loss) per share is computed using the weighted average number of shares outstanding. Diluted earnings (loss) 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.

The Company's calculation of earnings (loss) per share of common stock is as follows:

	Year Ended October 31,								
	2011			2010			2009		
	Net Income(Loss)	**Shares**	**Earnings (Loss) Per Share**	Net Income (Loss)	Shares	Earnings (Loss) Per Share	Net Income (Loss)	Shares	Earnings (Loss) Per Share
Earnings(loss) per share-Basic	**$ 3,518,000**	**10,042,000**	**$ 0.35**	$2,203,000	10,183,000	$ 0.22	$(14,454,000)	10,326,000	$(1.40)
Effect of dilutive shares of common stock from stock options ..	**-**	**32,000**	**-**	-	19,000	(-)	-		)
Earnings(loss) per share-Diluted ..	**$ 3,518,000**	**10,074,000**	**$ 0.35**	$2,203,000	10,202,000	$ 0.22	$(14,454,000)	10,326,000	$(1.40)

Forty thousand (40,000) outstanding option shares were excluded from the diluted earnings per share calculation at October 31, 2011 as they would have been antidilutive because the exercise price exceeded the market price. Ninety thousand (90,000) outstanding option shares were excluded from the diluted earnings per share calculation at October 31, 2010 as they would have been antidilutive because the exercise price exceeded the market price. Outstanding option shares (139,063) were excluded from the diluted loss per share calculation at October 31, 2009 as they would have been antidilutive due to the net loss for the year.

(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, 2011, common shares issued are 10,660,000, common shares held in treasury are

619,000 and common shares outstanding are 10,041,000. In addition, the Company has authorized 5,000,000 shares of preferred stock which may be issued in series and with preferences as determined by the Company's Board of Directors. Approximately 100,000 shares of the Company's authorized but unissued preferred stock have been reserved for issuance pursuant to the provisions of the Company's Shareholders' Rights Plan.

On September 22, 2008, the Company's Board of Directors authorized a stock repurchase Program and approved repurchase of the Company's common stock up to $2,000,000. On April 9, 2009, the Board expanded the program to $4,000,000 and on July 29, 2010 the program was expanded to $5,000,000. The repurchases may be made on the open market, in block trades or otherwise. The stock repurchase program may be expanded, suspended or discontinued at any time. At October 31, 2011, the Company has acquired 545,429 shares under the program, at an aggregate cost of $4,755,000.

(3) OIL AND NATURAL GAS PROPERTIES

Depreciation, depletion and amortization of oil and natural gas properties for the fiscal years ended October 31, 2011, 2010 and 2009 were $4,703,000, $3,129,000 and $3,931,000, respectively. The Company uses the full cost method of accounting for costs related to its oil and natural gas properties. Capitalized, evaluated, costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. Costs for unevaluated properties, which typically include lease rentals, geology and seismic costs, are capitalized but are excluded from amortizable costs during the evaluation period. When determinations are made whether the property has proved recoverable reserves or not, or if there is an impairment, the costs are reclassified to amortizable costs.

The Company performs a ceiling test each quarter. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices (discussed below), excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, at a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. The current prices utilized are based on the average of the first-day-of-the-month prices during the preceding twelve-month period pursuant to the SEC's "Modernization of Oil and Gas Reporting" rule. For fiscal year 2011, the average of the first-day-of-the-month oil price was $86.32 per barrel, and the average of the first-day-of-the-month gas price was $4.54 per Mcf.

Due primarily to the precipitous drop in natural gas prices during the first half of 2009, for the fiscal year ended October 31, 2009, the Company recorded non-cash ceiling test write-downs at the end of the first and second quarters, in the aggregate of $23,726,000.

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 the average Company wellhead prices in effect on the first day of each month of the preceding twelve months be used and held constant. The resulting valuation is a standardized mathematical calculation, and 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 average prices and costs in effect during the test period.

Marlis E. Smith, Jr., a member of the Company's Board of Directors since April 2009 and the Company's President and Chief Executive Officer since January 16, 2010, is the controlling member of certain entities that have participated as independent third party working interest owners in numerous oil and gas wells operated by Credo. During Credo's fiscal year ended October 31, 2011, the entities controlled by Mr. Smith owned interests in thirty nine such properties, most of which they owned before he become an officer and director of Credo. During that period, the entities received approximately $284,000 in oil and gas revenues and paid approximately $378,000 in drilling costs and operating expenses related to such interests. The entities controlled by Mr. Smith also own interests in numerous wells which are operated by third parties and in which Credo also owns an interest.

(4) STOCK BASED COMPENSATION

The following table summarizes stock option activity in the Company's stock-based compensation plans for the years ended October 31, 2011, 2010 and 2009.

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE	AGGREGATE INTRINSIC VALUE (1)	NUMBER OF SHARES EXERCISABLE	WEIGHTED AVERAGE FAIR VALUE AT GRANT DATE
Outstanding at October 31, 2008 ..	232,769	$ 9.04	$ 394,000	157,397	$ 680,000
Cancelled	(53,706)	14.31			
Outstanding at October 31, 2009 ..	179,063	7.46	530,000	169,063	511,000
Granted at fair value	50,000	9.30			
Exercised	(50,000)	5.93			
Outstanding at October 31, 2010 ..	179,063	8.40	184,000	124,063	565,000
Granted at fair value	30,000	12.45			
Exercised	(10)	5.93			
Cancelled	(30,000)	12.45			
Outstanding at October 31, 2011 ..	179,053	$ 8.40	$ 381,000	145,720	$ 565,000

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at October 31 of each year. If the exercise price exceeds the market value, there is no intrinsic value.

The fair value of the stock option grants are amortized over the respective vesting period using the straight-line method and assuming no forfeitures and cancelations. Based on the historical experience of the Company, except for specific identifiable events, forfeitures and cancellations are not significant. The large forfeiture and cancellation in 2011 and 2009 were not material due to the short period of time that the options were outstanding. Compensation expense related to stock options included in General and Administrative Expense for the years ended October 31, 2011, 2010 and 2009 are $61,000, $78,000 and $31,000 respectively. The estimated unrecognized compensation cost from unvested options as of October 31, 2011 was approximately $67,000, which is expected to be recognized over an average period of 1.2 years.

Stock options are granted at the fair market value of one share of Common Stock on the date of grant. Options granted to non-employee directors vest one third immediately and one third on each subsequent anniversary. Options granted to officers and other employees vest over three to four years. All outstanding options had a term of ten years at the date of grant.

The fair value of each option granted in 2011, 2010 and 2009 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair value of options granted during the periods presented.

	2011	2010	2009
Expected life of options	4 years	3 years	N/A - No grants in 2009
Risk free interest rates	2.28%	2.69%	
Estimated volatility	50.10%	51.60%	
Dividend yield	0.00%	0.00%	
Weighted average fair market value of options granted during the year.	$ 5.13	$ 3.46	

The following table summarizes information about options outstanding at October 31, 2011.

Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value
$ 5.93	89,053	1.6	$ 5.93	$ 352,000	89,053	5.93	352,000
12.78	40,000	5.1	12.78	-	40,000	12.78	-
9.30	50,000	8.2	9.30	29,000	16,667	9.30	9,000
$5.93 - $12.78	179,053	4.2	$ 8.40	$ 381,000	145,720	8.20	$ 361,000

(5) OIL AND NATURAL GAS DERIVATIVES

The Company manages exposure to commodity price fluctuations by periodically hedging a portion of estimated production when the potential for significant downward price movement is anticipated or to assure availability of cash flow for anticipated debt service. These transactions typically take the form of costless collars or forward short positions which are generally based upon the NYMEX futures prices. Hedge contracts are closed by purchasing offsetting positions. Such hedges are authorized by the Company's Board of Directors and do not exceed estimated production volumes for the months hedged. Contracts 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.

At October 31, 2011 the Company held short sales open derivative contracts for 6,000 barrels in each of the production months of January through December 2012 at prices ranging from $91.95 to $93.00. This hedge will be approximately 15% to 25% of estimated 2012 production. The Company held no open derivative contracts for natural gas.

The Company does not designate its derivatives as hedging instruments for financial reporting purposes. The location and amount of derivative fair values and related gain (loss) are indicated in the following tables.

	October 31, 2011	October 31, 2010
Current assets: Derivative Assets	8,000	32,000

Amount of commodity derivative gain or (loss) included in "Other Income and (Expense)":

	For the Year Ended October 31, 2011	2010	2009
Commodity Derivatives			
Realized Gains (Losses)	(191,000)	115,000	3,720,000
Unrealized Gains (Losses)	8,000	(73,000)	(1,641,000)

The Company has a derivative 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 available is $7,200,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the Company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the Company's bank, and prohibits funded debt in excess of $500,000.

Subsequent to October 31, 2011, the Company entered into a Revolving Credit Agreement that includes a hedging line of credit. See Note 6 to the Consolidated Financial Statements for further discussion of the credit lines. The Agreement is waiting final execution of the documents.

(6) DEBT

Subsequent to October 31, 2011, subject to final execution of certain legal documents, the Company agreed to enter into a Revolving Credit Agreement (the Agreement) with its principal bank, Bank of Oklahoma, NA. The Agreement consists of a $25 million credit facility. The Agreement will mature in December 2015. Credo's credit availability under the Agreement is governed by a Borrowing Base, the determination of which is made by the lender in its sole discretion, on a semi-annual basis, taking into consideration the estimated value of Credo's oil and gas properties based on pricing models determined by the lender at such time, in accordance with the lender's customary practices for oil and gas loans. The initial Borrowing Base will be $7 million. The available borrowing amount under the Agreement could increase or decrease based on such redetermination. In addition to the semi-annual redeterminations, Credo and the lender each have discretion at any time, but not more often than once during a calendar year, to have the Borrowing Base redetermined.

Credo must elect between one of two interest rates as follows:

(i) a rate that is based on interest rates applicable to dollar deposits in the London interbank market ("LIBOR Rate") plus 175 to 275 basis points, depending on Borrowing Base utilization; or

(ii) a rate based on the greatest of (a) the prime rate announced by the Bank of Oklahoma; or (b) the federal funds rate plus 1/2 of 1%.

The Agreement includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers, and acquisitions, and also include financial covenants. If the Company were to fail to perform its obligations under these covenants or other covenants and obligations, it could cause an event of default and the Agreement could be terminated and amounts outstanding could be declared immediately due and payable by the lender, subject to notice and cure periods in certain cases. Such events of default include non-payment, breach of warranty, non-performance of financial covenants, certain adverse judgments, change of control, or a failure of the liens securing the Borrowing Base.

(7) INCOME TAXES

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

As of October 31, 2011 the Company's 2008 and 2009 Federal tax returns had been audited by the IRS and a preliminary report was issued indicating an immaterial amount of additional tax was due. Subsequent to October 31, 2011 the Company was notified that its 2010 Federal tax return had been selected for examination. State tax returns remain subject to examination for 2008 through 2010, except Colorado, in which the 2007 tax year also remains open.

At October 31, 2011 the Company had $5,361,000 of statutory depletion carry forward for tax return purposes, which do not expire. The Company has net operating loss carryovers as of October 31, 2011 of $10,108,000. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operation loss was generated. If not utilized, these carryovers will expire in year 2030 through 2031. The Tax Reform Act of 1986 contains provisions that limit the utilization of net operating loss carryforwards if there has been a change in ownership as described in Internal Revenue Code Section 382. The Company believes that its net operating loss carryforwards as of October 31, 2011 are not limited by IRC Section 382.

ASC 740, Income Taxes, specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company's recorded income tax benefits will be fully realized. There were no unrecognized tax benefits at the beginning or at the end of the twelve-month periods ended October 31, 2011, 2010 and 2009.

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

	Years Ended October 31,		
	2011	2010	2009
Current	$ -	$ (132,000)	$ (481,000)
Deferred	1,270,000	744,000	(8,580,000)
Total income tax expense	$ 1,270,000	$ 612,000	$(9,061,000)

Federal taxes at the effective income tax rate differ from taxes at the U.S. Federal statutory income tax rate due to the following:

	Years Ended October 31,		
	2011	2010	2009
Federal taxes at statutory rate	**$ 1,646,000**	$ 985,000	$(8,216,000)
Graduated rates	**(29,000)**	(15,000)	244,000
State income taxes and other	**248,000**	144,000	(742,000)
Percentage depletion	**(595,000)**	(502,000)	(347,000)
Federal taxes at the effective rate	**$ 1,270,000**	$ 612,000	$(9,061,000)

The principal sources of temporary differences resulting in deferred tax assets and liabilities at October 31, 2011 and 2010 are as follows (certain prior year amounts have been reclassified for comparative purposes):

	October 31, 2011	October 31, 2010
Deferred tax assets:		
Percentage depletion carryforward	$ 1,823,000	$ 1,244,000
Intangible assets	215,000	248,000
Net operating loss carry forward	3,437,000	1,150,000
Total deferred tax assets	5,475,000	2,642,000
Deferred tax liabilities:		
Oil and gas assets	(9,473,000)	(5,635,000)
Derivative instruments	-	(8,000)
State taxes	(538,000)	(318,000)
Other	31,000	38,000
Total deferred tax liabilities	(9,980,000)	(5,923,000)
Net deferred tax liability	$ (4,505,000)	$ (3,281,000)

(8) FAIR VALUE MEASUREMENTS

The Company utilizes derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of its anticipated future oil and natural gas production. These derivatives are carried at fair value on the consolidated balance sheets. Additionally, the Company's short-term investments include professionally managed limited partnerships which include investments that are not publicly traded and may have less readily determinable market values. The accounting standards established a valuation hierarchy for disclosure of the inputs to valuation used to measure fair value. This hierarchy prioritizes the inputs into three broad levels as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

The classification of a financial asset or liability within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The determination of the fair values below incorporates various factors required under fair value accounting guidance, including the impact of the counterparty's non-performance risk with respect to the Company's financial assets and the Company's non-performance risk with respect to the Company's financial liabilities. The following table provides the assets and liabilities carried at fair value measured on a recurring basis as of October 31, 2011:

	Level 1	Level 2 (in thousands)	Level 3	Total
Asset:				
Short-term investments	$ 1,468	$ -	$ 19	$ 1,487
Derivative assets (current)	$ -	$ 8	$ -	$ 8

Level 3 instruments are comprised of the Company's investments in professionally managed limited partnerships. The fair value represents the net asset value of the Company's share in each partnership. The Company identified the investments as Level 3 instruments due to the fact that quoted prices for the underlying investments in the partnerships cannot be obtained and there is not an active market for the underlying investments or the partnerships shares. The Company utilizes the periodic fund statements to determine the valuation of its investment. Fair values derived from the statements are further substantiated by current fund redemption activity and communication with investment advisors.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the fiscal year ended October 31, 2011:

	(in thousands)
Balance as of October 31, 2010 (1)	$ 125
Total gains or losses (realized or unrealized) included in earnings (2)	1
Redemptions	(107)
Balance as of October 31,2011 (1)	$ 19

(1) This amount is included in short term investments on the balance sheet.
(2) This amount is included in investment income (loss) on the statement of operations.

(9) INTANGIBLE ASSETS

The patents underlying the Calliope Gas Recovery System are carried as a non-current asset on the Company's balance sheet and are being amortized over the average remaining life of the patents. The Company periodically evaluates this asset for realizability.

	October 31, 2010		October 31, 2011	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:				
Calliope intangible assets	$ 4,449,000	$ 872,000	$ 4,449,000	$ 1,308,000
Aggregate amortization expense:				
For the years ended October 31, 2010 and 2011		$ 436,000		$ 436,000

Estimated future amortization expense:	
For the year ended October 31, 2012	$ 436,000
For the year ended October 31, 2013	436,000
For the year ended October 31, 2014	436,000
For the year ended October 31, 2015	436,000
Thereafter	1,397,000
Total..	$ 3,141,000

In July 2008, the Company acquired the third party rights in producing properties and possible future Calliope installations for $975,000. As a result of the natural gas price collapse at January 31, 2009, the Company determined that the sum of the undiscounted value of cash flows to be derived was minimal. Accordingly, the Company recorded an impairment loss of $927,000 for the quarter ended January 31, 2009.

(10) COMPRESSOR, TUBULAR AND CALLIOPE INVENTORY

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

(11) 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 2011, 2010, and 2009 were $44,000 in each year.

Other Company Benefits

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

(12) COMMITMENTS AND CONTINGENCIES

The Company leases office facilities under an operating lease agreement entered into May 1, 2011 which expires April 30, 2016. The lease agreement requires monthly payments of $3,802 plus operating expenses. Total rental expense was $106,000 in 2011, $105,000 in 2010, and $107,000 in 2009. The Company has no capital leases and no other operating lease commitments at October 31, 2011.

The Company was named as a defendant in a lawsuit brought by a former employee. The suit, Pownell v. Credo Petroleum Corp. et al., U.S.D.C. for the District of Colorado, was settled on August 9, 2011 at an incremental cost to the Company, net of amounts previously paid or accrued, and net of insurance proceeds, of approximately $210,000. The total cost to the Company over the three years of litigation, including legal fees, was approximately $920,000.

(13) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

	October 31,		
	2011	2010	2009
Unevaluated properties not being amortized	**$ 9,609,000**	$ 8,801,000	$ 7,363,000
Properties being amortized	**99,283,000**	83,360,000	76,127,000
Accumulated depreciation, depletion and amortization...........	**(61,042,000)**	(56,339,000)	(53,211,000)
Total capitalized costs	**$ 47,850,000**	$ 35,822,000	$ 30,279,000

Unevaluated Oil and Gas Properties

Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until they are evaluated. The following table shows, by year incurred, the unevaluated oil and gas property costs (net of transfers to the full cost pool and sales proceeds) excluded from the amortization computation as of October 31, 2011:

Net Costs Incurred During Years Ended:	Total Unevaluated Properties
October 31, 2011	$ 5,239,000
October 31, 2010	1,980,000
October 31, 2009 and prior	2,390,000
	$ 9,609,000

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

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

	Years Ended October 31,		
	2011	2010	2009
Property acquisition costs net of divestiture proceeds:			
Unproved	**3,613,000**	3,102,000	4,364,000
Exploration costs	**11,464,000**	4,393,000	4,826,000
Development costs	**1,619,000**	1,207,000	2,203,000
Total before asset retirement obligation	**$ 16,696,000**	$ 8,703,000	$ 11,393,000
Total including asset retirement obligation	**$ 16,731,000**	$ 8,730,000	$ 11,480,000

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: DCP Midstream LLP 16% in 2011, 13% in 2010, and 28% in 2009, Coffeeville Resources 25% in 2011, 24% in 2010 and 37% in 2009.

Oil and Gas Reserve Data (Unaudited)

LaRoche Petroleum Engineers, LLC (LaRoche) and Netherland, Sewell and Associates, Inc. (NSA), our independent petroleum engineering consulting firms, prepared the Company's estimated reserves as of October 31, 2011. NSA prepared the estimated reserves for the properties located in the North Dakota Bakken and Three Forks properties. LaRoche prepared the estimated reserves as of October 31, 2010 and 2009.

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. For 2011 and 2010, the prices were calculated based on the average of spot prices on the first day of each month during the fiscal year. For 2009 the prices were calculated based on the spot price on the last day of the fiscal year. The average price used was $86.32, $68.30, and $69.24 per barrel for oil and $4.54, $4.49, and $4.49 per Mcf for gas in 2011, 2010, and 2009, respectively. Estimated future costs were calculated assuming continuation of costs and economic conditions at the reporting date.

Data presented for 2009 throughout this footnote is not required to be, nor has it been, updated based on the new guidance. The effect of adopting the new guidance did not significantly impact the Company's estimated quantity of total proved reserves.

The Company's reserves, and reserve values, are concentrated in 79 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2011, the Significant Properties represent 23% of the Company's total number of properties but a disproportionate 80% of the discounted value (at 10%) of the Company's reserves. Reserves related to new wells, including wells in the proved developed non-producing and proved undeveloped categories, comprise 27% of significant properties and 30% of the discounted value of significant properties.

Estimates of reserve quantities and values for certain 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 Calliope 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.

One measure of the life of the Company's proved reserves can be calculated by dividing proved reserves at fiscal year end 2011 by production for fiscal year 2011. This measure yields an average reserve life of 13.6 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, their 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.

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

	2011		2010		2009	
	Oil(bbls)	Gas(Mcf)	Oil(bbls)	Gas(Mcfs)	Oil(bbls)	Gas(Mcf)
Proved reserves:						
Balance, Beginning of year	954,000	13,938,000	876,000	14,940,000	710,000	15,525,000
Revisions of previous estimates......	227,000	(782,000)	6,000	(386,000)	(1,000)	247,000
Extensions and discoveries............	1,003,000	807,000	164,000	345,000	283,000	381,000
Purchases of reserves in place.......	-	95,000	5,000	412,000	-	16,000
Sales of reserves in place...............	(73,000)	(349,000)	-	(335,000)	-	-
Production............	(148,000)	(918,000)	(97,000)	(1,038,000)	(116,000)	(1,229,000)
Balance, October 31.......	1,963,000	12,791,000	954,000	13,938,000	876,000	14,940,000
Proved developed reserves:						
Beginning of year.........	501,000	8,971,000	454,000	9,633,000	449,000	10,621,000
End of year..............	705,000	7,772,000	501,000	8,971,000	454,000	9,633,000

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

	2011	2010	2009
Future cash inflows	$ 227,467,000	$127,672,000	$ 127,731,000
Future production and development costs	(111,150,000)	(57,807,000)	(55,868,000)
Future income tax expense	(23,867,000)	(14,898,000)	(15,119,000)
Future net cash flows	92,450,000	54,967,000	56,744,000
10% discount factor	(42,353,000)	(24,037,000)	(24,144,000)
Standardized measure of discounted future net cash flows	$ 50,097,000	$ 30,930,000	$ 32,600,000

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

	2011	2010	2009
Balance at beginning of year	$ 30,930,000	$ 32,600,000	$ 27,619,000
Sales of oil and gas produced, net of production costs	(12,767,000)	(8,375,000)	(6,807,000)
Net changes in prices and production costs	13,207,000	(51,000)	10,670,000
Extensions and discoveries	18,345,000	3,979,000	5,231,000
Changes in future development costs ..	(103,000)	(2,403,000)	(1,533,000)
Previously estimated development costs incurred during the period	281,000	1,246,000	1,499,000
Revisions of previous quantity estimates, timing, and other	1,783,000	(842,000)	(3,670,000)
Purchases of reserves in place	242,000	1,060,000	34,000
Sales of reserves in place	(1,243,000)	(361,000)	-
Accretion of discount	3,873,000	4,043,000	2,679,000
Net change in income taxes	(4,451,000)	34,000	(3,122,000)
Balance, October 31	$ 50,097,000	$ 30,930,000	$ 32,600,000

(14) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following is a tabulation of the Company's unaudited quarterly operating results for fiscal 2011, 2010 and 2009.

	Oil & Gas Sales	Income (Loss) Before Income Taxes	Net Income (Loss)	Basic Earnings (Loss) Per Share	Diluted Earnings (Loss) Per Share
Fiscal 2009:					
First Quarter	$ 2,108,000	$ (16,281,000)	$ (9,891,000)	$ (0.95)	$ (0.95)
Second Quarter	2,353,000	(7,655,000)	(4,710,000)	(0.46)	(0.46)
Third Quarter	2,837,000	580,000	353,000	0.03	0.03
Fourth Quarter	2,769,000	(159,000)	(206,000)	(0.02)	(0.02)
	$ 10,067,000	$ (23,515,000)	$ (14,454,000)	$ (1.40)	$ (1.40)
Fiscal 2010:					
First Quarter	$ 3,142,000	$ 864,000	$ 639,000	$ 0.06	$ 0.06
Second Quarter	2,945,000	793,000	603,000	0.06	0.06
Third Quarter	2,917,000	708,000	555,000	0.06	0.06
Fourth Quarter	2,562,000	450,000	406,000	0.04	0.04
	$ 11,566,000	$ 2,815,000	$ 2,203,000	$ 0.22	$ 0.22
Fiscal 2011:					
First Quarter	$ 3,250,000	$ 225,000	$ 169,000	$ 0.02	$ 0.02
Second Quarter	4,068,000	326,000	255,000	0.03	0.03
Third Quarter	4,488,000	2,329,000	1,707,000	0.17	0.17
Fourth Quarter	4,961,000	1,908,000	1,387,000	0.14	0.14
	$ 16,767,000	$ 4,788,000	$ 3,518,000	$ 0.35	$ 0.35

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Credo Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Credo Petroleum Corporation and subsidiaries as of October 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended October 31, 2011. 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Credo Petroleum Corporation and subsidiaries at October 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended October 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Credo Petroleum Corporation's internal control over financial reporting as of October 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated January 17, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
January 17, 2012

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Credo Petroleum Corporation

We have audited Credo Petroleum Corporation's internal control over financial reporting as of October 31, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Credo Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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, Credo Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of October 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Credo Petroleum Corporation and subsidiaries as of October 31, 2011 and 2010 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended October 31, 2011 and our report dated January 17, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
January 17, 2012

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Attached as exhibits to this report are certifications of our CEO and CFO required pursuant to Rule 13a-14 under the Exchange Act. This section includes information concerning the controls and procedures evaluation referred to in the certifications.

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of October 31, 2011. This evaluation was conducted under the supervision and with the participation of management, including our

CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that, subject to the limitations noted in this section, as of October 31, 2011, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our 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 that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the Company, (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 only in accordance with authorizations of management and directors of the Company 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.

Under the supervision and with the participation of our management, including our CEO and CFO, we assessed our internal control over financial reporting as of October 31, 2011, the end of our fiscal year. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management has concluded that our internal control over financial reporting was effective as of October 31, 2011.

The effectiveness of our internal control over financial reporting as of October 31, 2011 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the quarterly period ended October 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Effectiveness of Controls. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Additionally, 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.

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 AND 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 incorporated herein by reference from the Company's definitive proxy statement for its annual meeting of stockholders to be filed with the United States Securities and Exchange Commission within 120 days after the end of the fiscal year ended October 31, 2011.

PART IV

ITEM 15. EXHIBITS AND 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(i) Amended and Restated Certificate of Incorporation of CREDO Petroleum Corporation, a Delaware corporation (incorporated herein by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).

3(ii) Bylaws of CREDO Petroleum Corporation, a Delaware corporation (incorporated herein by reference to Exhibit 3.2 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).

4.1 Shareholders' Rights Plan, dated April 11, 1989.

4.2 Amendment to Shareholders' Rights Plan, dated February 24, 1999 (incorporated into Part II of the Company's Form 10-QSB dated January 31, 1999).

4.3 Second Amendment to Rights Agreement, dated as of June 3, 2008, by and between the Company and Computershare Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 3, 2008).

4.4 Third Amendment dated as of April 9, 2009 to Rights Agreement dated as of April 11, 1989 between Credo Petroleum Corporation, a Delaware corporation, and Computershare Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).

4.5 Rights Agreement, dated April 9, 2009 between Credo Petroleum Corporation, a Delaware corporation and Computershare Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).

10.1 CREDO Petroleum Corporation 1997 Stock Option Plan, as amended and restated effective October 25, 2001 (incorporated by reference to Form 10-KSB dated October 31, 2001).

10.2	CREDO Petroleum Corporation 2007 Stock Option Plan (incorporated by reference to the Company's definitive proxy statement filed with the SEC on February 20, 2007).
10.3	Employment Agreement by and between CREDO Petroleum Corporation and Marlis E. Smith, Jr. dated as of December 21, 2009, effective as of January 16, 2010(incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 28, 2009).
14.1	Code of Business Conduct and Ethics (incorporated by reference to Form 10-KSB dated October 31, 2004).
21	CREDO Petroleum Corporation (a Delaware 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 17, 2011.
31.1 *	Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 *	Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 *	Certification by Chief Executive Officer and Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act (18 U.S.C. Section 1350).
99.1*	LaRoache Petroleum Consultants, Ltd. Reserve Report.
99.2*	Netherland, Sewell & Associates, Inc. Reserve Report

* Filed with this Form 10-K.

** Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Statement of Operations for the years ended October 31, 2011, 2010 and 2009, (ii) the Condensed Consolidated Balance Sheet at October 31, 2011 and 2010, and (iii) the Condensed Consolidated Statement of Cash Flows for the years ended October 31, 2011 and 2010.

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 17, 2012.

CREDO PETROLEUM CORPORATION
(Registrant)

By: /s/ Marlis E. Smith, Jr.
Marlis E. Smith, Jr.,
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 17, 2012	/s/ Marlis E. Smith, Jr. Marlis E. Smith, Jr.	Director and Chief Executive Officer (Principal Executive Officer)
January 17, 2012	/s/ Alford B. Neely Alford B. Neely	Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)
January 17, 2012	/s/ James T. Huffman James T. Huffman	Chairman of the Board of Directors
January 17, 2012	/s/ Clarence H. Brown Clarence H. Brown	Director
January 17, 2012	/s/ Oakley Hall Oakley Hall	Director
January 17, 2012	/s/ W. Mark Meyer W. Mark Meyer	Director
January 17, 2012	/s/ John A. Rigas John A. Rigas	Director
January 17, 2012	/s/ H. Leigh Severance H. Leigh Severance	Director
January 17, 2012	/s/ William F. Skewes William F. Skewes	Director

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Corporate Information

Corporate Headquarters
Credo Petroleum Corporation
1801 Broadway, Suite 900
Denver, Colorado 80202
Tel 303-297-2200
Fax 303-297-2204

Web Site
www. Credopetroleum .com

Common Stock Traded on NASDAQ Global Market
Symbol: CRED

Common Shares Outstanding
February 9, 2012: 10,041,164

Transfer Agent and Registrar
Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden, Colorado 80401

Independent Registered Public Accounting Firm
Ernst & Young, LLP
Denver, Colorado

Board of Directors
Clarence H. Brown
Oakley Hall
James T. Huffman
W. Mark Meyer
John A. Rigas
H. Leigh Severance
William F. Skewes
Marlis E. Smith, Jr.

Officers
Michael D. Davis — Chief Operating Officer and Chief Executive Officer (Interim)

Marlis E. Smith, Jr. — Chief Executive Officer, through January 31, 2012

Alford B. Neely — Chief Financial Officer , Treasurer and Secretary

Corporate Counsel
Davis Graham & Stubbs LLP
Denver, Colorado

Kirk & Chaney
Oklahoma City, Oklahoma

Corporate Profile

Credo Petroleum Corporation is an independent oil and gas exploration and production company founded in 1978 and headquartered in Denver, Colorado. Credo is conducting record oil-focused drilling programs in the Bakken and Three Forks play in North Dakota, the Lansing Kansas City play in Kansas and Nebraska, and the Tonkawa and Cleveland plays in the Texas Panhandle. In the fourth quarter of 2011, the Company achieved the milestone of becoming primarily an oil producer, and expects to achieve a significant overweighting of oil in both its production and reserves in 2012. Credo's patented Calliope Gas Recovery System™ recovers stranded gas from low pressure gas reservoirs. The Company has a time-honored commitment to maintaining profitability and financial strength.

Credo Petroleum Corporation
2011 Annual Report