CREDO PETROLEUM CORP
Form 10-K
January 17, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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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

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

For the transition period from to

Commission File Number 0-8877

CREDO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

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: o 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: o 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 o 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 o 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 o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act) o 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.

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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.

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

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

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

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PART I

ITEM 1. BUSINESS

General

Credo Petroleum Corporation (Credo) was incorporated in Colorado in 1978 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

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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.

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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

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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

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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.

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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

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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

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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.

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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.

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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

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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 Gross	Net	Royalty Interest Acreage 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.

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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.

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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 MarketSM 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.

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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.

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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.

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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.

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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.

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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, 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

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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

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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:

	For The Year Ended October 31,		
	2011	**2010**	**2009**
RECONCILIATION OF EBITDA:			
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	$

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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,

Product		**Net Wellhead Price**		**2011 Realized Derivative (Loss)**		**Effective Price Realization**		**Net Wellhead Price**		**2010 Realized Derivative Gain**		**Effective Price Realization**		**Net Wellhead Price**		**2009 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.

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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.

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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

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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.

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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

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CONSOLIDATED BALANCE SHEETS

October 31, 2011 and 2010

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

		2011		2010
ASSETS				
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				
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.

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CONSOLIDATED STATEMENTS OF OPERATIONS

For the Three Years Ended October 31, 2011

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

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.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

For the Three Years Ended October 31, 2011

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock Shares	Common Stock Amount	Capital In Excess Of Par Value	Treasury Stock	Retained Earnings	Total Stockholders Equity
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.

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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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

October 31, 2011

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Presentation

The consolidated financial statements include the accounts of Credo Petroleum Corporation and its wholly owned subsidiaries (the Company). The Company engages in oil and gas acquisition, exploration, development and production activities in the United States. 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.

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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:

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	October 31, 2011		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 o