CREDO PETROLEUM CORP
Form 10KSB
January 27, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-KSB

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

For The Fiscal Year Ended October 31, 2004

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

For the transition period to
Commission File Number 0-8877

CREDO PETROLEUM CORPORATION

(Exact name of registrant as specified in charter)

Colorado	**84-0772991**
(State of incorporation)	(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
6,037,000 Shares Outstanding, Net of Treasury Stock,
at the Close of Business on December 31, 2004
(Title of class and shares outstanding)

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-B 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-KSB or any amendment to this Form 10-KSB. ý

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

Issuer's revenues for its most recent fiscal year: $10,314,000

As of December 31, 2004, the aggregate market value of common stock held by non-affiliates of the registrant was approximately $62,233,000.

DOCUMENTS INCORPORATED BY REFERENCE into Part III hereof Proxy Statement to be filed with the Commission in connection with the company's 2004 Annual Meeting.

Transitional Small Business Format (Check One): Yes o No ý

PART I.

ITEM 1. BUSINESS

General

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

Business Activities

The company focuses on two core projects natural gas drilling in the Northern Anadarko Basin of Oklahoma and recovering standard gas from low-pressure reservoirs using its patented Calliope Gas Recovery System ("Calliope").

Drilling operations are concentrated on medium depth properties generally ranging from 7,000 to 10,000 feet. The company enters into various types of cost sharing arrangements with industry participants on most of its operating activities.

The company acts as "operator" of approximately 102 wells pursuant to standard industry Operating Agreements, and it owns working and royalty interests in approximately 128 wells which are operated by outside parties.

Over the past five years, the company has participated in developing, testing, refining, and patenting Calliope. Calliope efficiently lifts fluids from wellbores using pressure differentials, thus allowing gas previously trapped by fluid build-up in the wellbore to flow to the surface. The company believes Calliope is clearly different from all other fluid lift technologies because it does not rely on bottom-hole pressure and has only one down-hole moving part. Calliope is primarily applicable to mature natural gas wells in low pressure, gas expansion reservoirs at depths below 8,000 feet. To date, Calliope has not required external capital. During 2000, the company purchased an unrestricted, exclusive license to the technology. The term of the license is 10 years, and it can be extended an additional five years to cover the entire 15 year term of the patent. At year end, Calliope was installed on 16 wells ranging at depth from 6,500 feet to 18,400 feet. The company believes it has proven Calliope's economic viability and flexibility over a wide range of applications.

Markets and Customers

Marketing of the company's oil and gas production is influenced by many factors which are beyond the company's control and the exact effect of which cannot be accurately predicted. These factors include changes in supply and demand, market prices, regulation, and actions of major foreign producers. Oil price fluctuations can be extremely volatile as was demonstrated when, during 2003, the posted price for West Texas intermediate fell below $25.00 per barrel and then rose to over $50.00 per barrel late in 2004.

Gas price decontrol, the advent of an active spot market for natural gas, changes in supply and demand for natural gas, and weather patterns cause natural gas prices to be subject to significant fluctuations. The company presently sells virtually all of its gas under one to five year contracts with major pipeline companies. The sales price is typically based on monthly "spot" (Index) prices for the applicable production region. Title to the 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 gas pipelines in this area, thereby reducing the number of available purchasers. In many instances, there may be only one viable pipeline option, which enables the pipeline to charge higher rates.

Over the past few years there has been increasing concern that a supply/demand imbalance has developed in domestic natural gas based on increasing demand and lower deliverability. This, together with rising oil prices, political unrest and uncertainty in certain major producing regions and active fund speculation in the natural gas derivatives market has caused natural gas prices to become increasingly volatile. The result has been higher domestic natural gas prices beginning in 2000 compared to the previous 10 years. The company expects these historically strong prices to continue for several years but cannot reasonably predict the extent or timing of natural gas price fluctuations.

As discussed elsewhere in this Form 10-KSB, the company periodically hedges the price of a portion of its estimated natural gas production by forward selling on the NYMEX futures market.

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

Information concerning the company's major customers is included in Note (6) to the Consolidated Financial Statements.

Competition and Regulation

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

Oil and gas drilling and production operations are regulated by various Federal, state and local agencies. These agencies issue binding rules and regulations which carry penalties, often substantial, for failure to comply. The company anticipates its aggregate burden of Federal, state and local regulation will continue to increase particularly in the area of rapidly changing environmental laws and regulations. The company also believes that its present operations substantially comply with applicable regulations. To date, such regulations have not had a material effect on the company's operations, or the costs thereof. There are no known environmental or other regulatory matters related to the company's operations which are reasonably expected to result in material liability to the company. The company does not believe that capital expenditures related to environmental control facilities or other regulatory matters will be material in 2005. The company cannot predict what subsequent legislation or regulations may be enacted or what effect it will have on the company's business.

ITEM 2. PROPERTIES

General

The company's drilling activities are primarily located along the shelf of the Northern Anadarko Basin of Oklahoma and in the Oklahoma Panhandle. Specifically, drilling expenditures have been focused on four prospects comprising approximately 23,000 gross acres located in Harper, Ellis and

Beaver Counties, Oklahoma. Wells target the Morrow and Chester formations between 7,000 and 10,000 feet. Since 2001, the company has participated in drilling 39 wells on the four properties with interests ranging up to 60%. Of those wells, 31 were completed as producers and eight were dry holes. Several of the wells are exceptional for the area, and 13 of the wells are included in the company's Significant Properties (see definition below). Three of the prospects have ample room for additional drilling and the company believes that more good wells will be drilled.

The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. Calliope is a new generation of fluid lift technology that is applicable to gas wells that meet certain criteria. Calliope achieves substantially lower flowing bottom hole pressure than conventional production methods because it does not rely on reservoir pressure to lift liquids. The company believes it has proven that Calliope will add 0.5 to 2.0 Bcf of proved gas reserves to many dead and uneconomic wells. The company also believes there are presently more than 1,000 wells that meet its general criteria for Calliope candidate wells and thousands more that will meet its general Calliope criteria in the future.

Calliope operations are currently focused in Oklahoma where the company has a significant field operations infrastructure. Most Calliope wells are located in the Northern Anadarko Basin of Oklahoma. To date, Calliope has been installed on 20 wells ranging in depth from 6,500 to 18,400 feet. All of the wells were either dead or uneconomic at the time Calliope was installed. Nine of the wells involved various prototype applications. Eleven Calliope wells are included in the company's Significant Properties.

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

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

The company's reserves, and reserve values, are concentrated in 43 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At year-end, the Significant Properties represent 24% of the company's total properties but a disproportionate 75% of the discounted value (at 10%) of the company's reserves. Individual Calliope wells comprise 26% of the Significant Properties and represent 37% of the discounted reserve value of such properties. Wells drilled on the four prospects discussed above (Item 2. Properties, General) comprise 30% of the Significant Properties and represent 30% of the discounted value of such properties.

Estimates of reserve quantities and values for certain Significant Properties must be viewed as being subject to significant change as more data about the properties becomes available. Such properties include wells with limited production histories (including post Calliope installation wells) and properties with proved undeveloped or proved non-producing reserves. In addition, Calliope wells are generally mature wells. As such, they contain older down-hole equipment that is more subject to failure than new equipment. The failure of such equipment, particularly casing, can result in complete loss of a well. McCartney Engineering, Inc., an independent petroleum engineering firm, estimated proved reserves for the company's properties which represented 61% in 2004, 64% in 2003, and 62% in 2002 of the total estimated future value of estimated reserves. Remaining reserves were estimated by the company in all years. At October 31, 2004, natural gas represented 86% and crude oil represented 14% of total reserves denominated in equivalent barrels using a six Mcf of gas to one barrel of oil conversion ratio.

The following table sets forth, as of October 31 of the indicated year, information regarding the company's proved reserves which is based on the assumptions set forth in Note (6) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $50.43, $28.64 and $26.76 per barrel of oil and $5.84, $3.99

and $3.74 per Mcf of gas as of October 31, 2004, 2003 and 2002, respectively. Amounts do not include estimates of future Federal and state income taxes.

Year	Oil (bbls)	Gas (Mcf)	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2004	**407,000***	**15,273,000***	**$ 77,612,000**	**$ 44,551,000**
2003	385,000*	13,786,000*	$ 45,165,000	$ 28,024,000
2002	337,000*	9,415,000*	$ 29,774,000	$ 18,035,000

* In 2002 and 2003, substantially all of the company's reserves are classified as proved developed, and in 2004, 93% are classified as proved developed.

Production, Average Sales Prices and Average Production Costs

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

	2004		2003		2002	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Gas (Mcf)	**1,710,000**	**$ 4.60**	1,449,000	$ 4.50	1,298,000	$ 3.00
Oil (bbls)	**41,000**	**$ 36.57**	35,000	$ 27.68	37,000	$ 22.01

Average production costs, including production taxes, per equivalent unit of production (using a six to one conversion ratio of Mcfs to barrels) were $6.37, $5.82 and $5.10 per equivalent barrel in 2004, 2003 and 2002, respectively.

Productive Wells and Developed Acreage

Developed acreage at October 31, 2004 totaled 25,200 net and 142,800 gross acres. At October 31, 2004, the company owned working interests in 69.53 net (230 gross) wells consisting of 16.23 net (43 gross) oil wells and 53.30 net (187 gross) gas wells. In addition, the company owned royalty and production payment interests in approximately 977 wells, primarily coal bed methane located in Wyoming. In 2004, the company sold or abandoned 0.31 net (3 gross) wells. In the same period, the company drilled and acquired interests in 5.35 net (26 gross) wells in which it did not previously own an interest.

Undeveloped Acreage

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

Expiration Year Ending October 31	Royalty Interest Acreage		Working Interest Acreage	
	Gross	Net	Gross	Net
2005	4,400	500	16,200	5,100
2006	500		15,800	6,600
2007			5,700	2,600
2008	3,300	100	4,200	500
2009			700	200
Thereafter			3,100	700
Held-By-Production	150,400	8,000	17,400	3,700
	158,600	8,600	63,100	19,400

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

Drilling

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

Gross Wells

Year Ended October 31	Total Gross Wells	Exploratory			Development		
		Oil	Gas	Dry	Oil	Gas	Dry
2004	**25**	**1**	**3**	**4**		**14**	**3**
2003	21		12	3		6	
2002	13		6	2		5	
1978-2001	221	12	95	76	15	18	5
	280	13	116	85	15	43	8

Net Wells

Year Ended October 31	Total Gross Wells	Exploratory			Development		
		Oil	Gas	Dry	Oil	Gas	Dry
2004	**6.899**	**.306**	**1.381**	**2.074**		**1.980**	**1.158**
2003	4.906		2.564	0.762		1.580	
2002	3.212		2.032	0.925		0.255	
1978-2001	35.715	1.557	14.030	11.493	4.350	2.300	1.985
	50.732	1.863	20.007	15.254	4.350	6.115	3.143

ITEM 3. LEGAL PROCEEDINGS

The company is not a party to any material pending legal proceedings. No such proceedings have been threatened and none are contemplated by the company.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2004.

PART II.

ITEM 5. MARKET FOR THE COMPANY'S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

The company's common stock is traded on the National Association of Securities Dealers Automated Quotation System under the symbol "CRED". Market quotations shown below were reported by the National Association of Securities Dealers, Inc. and represent prices between dealers excluding retail mark-up or commissions.

	2004		2003	
Quarter Ended	**High**	**Low**	**High**	**Low**
January 31	**$ 13.50**	**$ 10.71**	$ 6.31	$ 4.13
April 30	**16.67**	**11.99**	9.87	6.33
July 31	**18.79**	**14.01**	10.67	7.13
October 31	**17.39**	**12.27**	11.86	8.40

At December 31, 2004, the company had 2,932 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. The company issued a 3-for-2 stock split in 2004 and a 20% stock dividend during 2003.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Liquidity and Capital Resources

References to years as used in this Item indicate fiscal years ended October 31.

At October 31, 2004, working capital was $5,611,000, compared with $6,577,000 at October 31, 2003. Net cash provided by operating activities for the years ended October 31, 2004, 2003 and 2002 was $4,618,000, $5,891,000 and $2,555,000, respectively. The decrease in cash flows from operating activities can be attributed primarily to a net increase of $1,593,000 in short term investments in 2004 versus a net decrease in short term investments of $808,000 in 2003. This net increase in investments of $2,401,000 more than offset cash flow increases from net income, DD&A and deferred income taxes which totaled approximately $1,414,000. For the years ended October 31, 2004, 2003 and 2002, cash used in investing activities was $6,179,000, $5,332,000 and $2,165,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $5,671,000, $5,520,000 and $2,464,000, respectively. Additional expenditures for oilfield tubulars and compressors were incurred during 2004 and 2003 totaling $825,000 and $338,000, and are classified as other long-term assets. The company purchased these tubulars to insure availability for its drilling program.

The average return on CREDO's investments was 5% in 2004, 10% in 2003, and 3% in 2002. At year-end approximately 60% of the investments were directly invested in mutual funds and were managed by professional money managers. Remaining investments are in managed partnerships that use various strategies to minimize their correlation to stock market movements. Most of the investments are highly liquid and the company believes they represent a responsible approach to cash management. In the company's opinion, the greatest investment risk is the potential for negative market impact from unexpected, major adverse news, such as the September 11th terrorist attacks.

Existing working capital and anticipated cash flow are expected to be sufficient to fund 2005 operations. At year-end, the company had not utilized lines of credit or other bank financing arrangements. Because earnings are anticipated to be reinvested in operations, cash dividends are not expected to be paid in the foreseeable future. Commitments for future capital expenditures were not material at year-end. The company has no defined benefit plans and no obligations for post retirement employee benefits.

Product Prices and Production

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

Although product prices are key to the company's ability to operate profitably and to budget capital expenditures, they are beyond the company's control and are difficult to predict. Since 1991, the company has periodically hedged natural gas prices by forward selling a portion of its estimated production in the NYMEX futures market. This is generally done when (i) the price relationship (the "basis") between the futures markets and the cash markets where the company sells its gas is stable within historical ranges, and (ii) in the company's opinion, the current price is adequate to insure reasonable returns at a time when downside price risks appear to be substantial. The company closes its hedges by purchasing offsetting "long" positions in the futures market at then prevailing prices. Accordingly, the gain or loss on the hedge position will depend on futures prices at the time offsetting "long" positions are purchased. Hedging gains and losses are included in revenues from oil and gas sales. The company believes its most significant hedging risk is that expected correlations in price movements as discussed above do not occur, and thus, that gains or losses in one market are not fully offset by opposite moves in the other market.

At January 12, 2005, the company had open hedge positions totaling 380 MMcf covering the months of February through June 2005. The hedges represent about one-third of the company's estimated natural gas production for the period. Of the February and March hedges, 75% are collars with a $6.12 floor and a $7.95 ceiling and the remainder are short positions at $6.51. Of the April through June hedges, 80% are collars with a $5.50 floor and a $6.75 ceiling and the remainder are short positions at $6.38. All prices are NYMEX basis. Hedges for the months of November through January have been closed at a loss of $180,000 (after tax). Average gas prices in the company's market areas are expected to be 15% to 17% below NYMEX prices due to basis differentials and transportation costs.

The company has a hedging line of credit with its bank which is available, at the discretion of the company, to meet margin calls. To date, the company has not used this facility and maintains it only as a precaution. The maximum credit line is $2,000,000 with interest calculated at the prime rate. The facility is unsecured and requires the company to maintain $3,000,000 in cash or short term investments and prohibits unfunded debt in excess of $500,000. It expires on October 31, 2006.

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

	2004		**2003**		**2002**	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Gas (Mcf)	**1,710,000**	**$ 4.60**	1,449,000	$ 4.50	1,298,000	$ 3.00
% change	**+18%**	**+2%**	+12%	+50%	+62%	-40%
Oil (bbls)	**41,000**	**$ 36.57**	35,000	$ 27.68	37,000	$ 22.01
% change	**+18%**	**+32%**	-5%	+26%	-16%	-17%

The 2004 and 2003 increases in natural gas volumes resulted primarily from successful drilling in Oklahoma. Most oil and condensate volumes are associated with gas production and, therefore, vary from well to well depending on the volume and "richness" of gas produced. Significant Properties (see definition on page 4) contributed 63% of 2004 production on a gas-equivalent basis.

As to Significant Properties, wells drilled since 2001 contributed 50% of 2004 production while Calliope wells installed during the same period contributed 18% of such production. Refer to Item 2, "Properties", for disclosures regarding reserve values on Significant Properties.

Oil and Gas Activities

General. Capital spending in 2004 totaled $7,089,000, a 30% increase over last year. During the year the company continued to focus on its two core projects natural gas drilling along the shelf of the Northern Anadarko Basin of Oklahoma and application of its patented Calliope Gas Recovery System.

The company believes that, in combination, these two core projects provide an excellent (and possibly unique) balance for achieving the company's goal of adding high quality gas reserves and production at reasonable costs and risks. In general, Calliope is reserve driven while new drilling is production rate driven. Calliope adds long-lived reserves at moderate costs and low risks. In most of the applications to date, Calliope has developed more reserves than the average new well drilled by the company at about one-half the cost and a small fraction of the risk. However, because Calliope is applied to mature, low pressure gas reservoirs, its initial production rates are generally significantly lower than initial rates for the successful new well drilled by the company. In contrast, drilling new wells is much higher in risk and cost than Calliope (particularly for comparable reserves) but, when successful, provides higher initial production rates and cash flow. However, production decline rates on new wells are generally much steeper than on Calliope wells.

In a business that is generally driven by production rates and cash flow, Calliope provides excellent balance by adding long-lived reserves at moderate costs and low risks. The company generally expects its success with these two core projects to occur unevenly and, therefore, believes they must be evaluated over a three to five year period.

Drilling Activities. During 2004, the company drilled 25 wells in Oklahoma and Wyoming with working interests ranging up to 65%. Eighteen (18) of the wells were completed as producers and seven were dry holes. Drilling expenditures were concentrated in Ellis and Harper Counties, Oklahoma on the company's 14,000 gross acre Sand Creek Prospect and its 6,000 gross acre Two Springs Prospect where 8 wells were drilled. The wells targeted the Morrow and Chester formations between 7,000 and 9,000 feet. Both the Sand Creek and Two Springs properties have ample room for additional wells to be drilled and the company believes that more excellent wells are likely.

Drilling is not restricted to the Sand Creek and Two Springs Prospects. The company has drilled wells and is generating prospects elsewhere in the Northern Anadarko Basin, in the Oklahoma Panhandle, and north-central Oklahoma. In addition, 10 coal bed methane wells were drilled on acreage in Wyoming where the company owns working interests of approximately 10%, and 132 coal bed methane wells were drilled on Wyoming acreage where the company owns small royalty interests.

A promising well was drilled on the company's 1,280 gross acre Gage Prospect located in Ellis County, Oklahoma which commenced production in the first quarter of fiscal 2005. Another promising well was drilled shortly after fiscal year-end on the company's 3,840 gross acre Glacier Prospect located in Harper County, Oklahoma. The well is not expected to commence production until February 2005. The company owns a 50% working interest in the first well and 70% in the second well.

The company replaced 183% of the reserves produced in 2004 and its reserve replacement cost was $1.98 per Mcf of gas-equivalent. According to John S. Herold, Inc.'s *Global Upstream Performance Review,* the company's average reserve replacement costs for 2001 through 2003 ranked in the best quartile of U.S. companies.

Calliope Gas Recovery System. Calliope systems are currently installed on 16 wells, all company-operated. Eleven of these wells are included in the company's Significant Properties (see Item 1, "Properties-General"). The 11,800-foot J. C. Carroll well provides an excellent example of Calliope's potential. When the well was purchased for salvage value in 1999, it had not produced commercially in five years. Calliope immediately restored production to 660 Mcfg (thousand cubic feet of gas) per day. Calliope has already recovered about 0.8 Bcfg from the Carroll well and the company estimates it will recover an additional 0.5 Bcfg.

The company's non-prototype Calliope wells have average reserves of 1.1 Bcfg and average initial daily production rates of 270 Mcfg, ranking them in the top 15% of all U. S. onshore producing wells. The company has proven that Calliope will effectively lift liquids in many varied applications, including wells with packers and depths to 18,400 feet.

During 2004, the company built on Calliope's flexibility by continuing to expand Calliope's operating envelope and buttressing its track record. One expansion project involved installing Calliope on wells where very small i.d. (inside diameter), 2.375-inch tubing is set with a packer. The initial prototype for this project appears to be a significant success. A second 2.375-inch Calliope prototype application is being installed. Based on engineering projections and the outcome on the initial well, the company believes Calliope will work effectively on many wells where 2.375-inch tubing is set with a packer and where relatively minor amounts of fluid must be removed from the wellbore.

A second expansion project involves using Calliope to help overcome reservoir damage which is often caused by the "parting shots" of previous operators. This two-stage process first treats the well in an attempt to re-establish good communication between the reservoir and the wellbore. In the second stage, Calliope removes the treatment fluids from the wellbore to allow gas to flow. Without Calliope, many reservoir treatments are not viable for low-pressure reservoirs because there is no practical way to remove the treatment fluids.

Three wells with very significant reservoir damage are included in this project. The project was partially successful on one well, restoring daily production to about 70 Mcfg, and was not successful on another well due to the extent of reservoir damage. An extensive workover is complete on a third well and Calliope has recently been installed.

The company's primary challenge has been obtaining candidate wells on the needed scale. In addition, wells that are available for purchase often have mechanical problems or problems caused by the seller's "parting shots" which preclude successful Calliope installations. The company has implemented a number of strategies to realize the value of Calliope and has retained highly qualified personnel to execute its strategies. Those strategies include joint venturing with larger companies that operate a significant number of wells which are potential Calliope candidates. Initial Calliope joint venture presentations have been made to a limited number of companies, all of which have expressed a keen interest in the technology.

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

Results of Operations

In 2004, total revenues rose 21% to $10,314,000 compared to $8,491,000 in 2003. As the oil and gas price/volume table on page 8 shows, total gas price realizations, which reflect hedging transactions, rose 2% to $4.60 per Mcf and oil price realizations rose 32% to $36.57 per barrel. The net effect of these price changes was to increase oil and gas sales by $963,000. Hedging losses were $717,000 in 2004 compared to $92,000 in 2003. Gas and oil production both rose 18%. The net effect of these volume changes was to increase oil and gas sales by $1,535,000. The increase in volumes resulted primarily from successful drilling in 2004 and 2003. Operating income rose 13% due to drilling supervision income and additional operated wells. Investment income and other fell 26% due primarily to market declines.

In 2004, total costs and expenses rose 24% to $5,244,000 compared to $4,244,000 in 2003. Oil and gas production expenses rose 29% due primarily to increased production taxes on higher revenues and new wells added during the year. Depreciation, depletion and amortization ("DD&A") increased 31% due primarily to increased production volume. General and administrative expenses rose 10% primarily due to increases in salaries and benefit costs. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28% in 2004 and 2003.

In 2003, total revenues increased 58% to $8,491,000 compared to $5,358,000 in 2002. As the oil and gas price/volume table on page 8 shows, total gas price realizations, which reflect hedging transactions, increased 50% to $4.50 per Mcf and oil price realizations rose 26% to $27.68 per barrel. The net effect of these price changes was to increase oil and gas sales by $2,760,000. Hedging losses were $92,000 in 2003 compared with gains of $505,000 in 2002. Gas production rose 12% and oil production declined 5%. The net effect of these volume changes was to increase oil and gas sales by $633,000. The increase in gas volumes resulted primarily from successful drilling in 2003 and 2002. Operating income rose 10% due to drilling supervision income and additional operated wells. Investment income and other rose 168% due primarily to improved market conditions.

In 2003, total costs and expenses rose 18% to $4,244,000 compared to $3,602,000 in 2002. Oil and gas production expenses rose 25% due primarily to increased production taxes on higher revenues and new wells added during the year. Depreciation, depletion and amortization ("DD&A") increased 11% primarily due to an increase in production volume. General and administrative expenses rose 19% due to expenses related to installation of, and conversion to updated accounting software, and increased salary costs. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28% in 2003 and 27% in 2002.

Critical Accounting Policies and Estimates

Accounting for Oil and Gas Property Costs. As more fully discussed in Note 1 to the consolidated financial statements, the company (i) follows the full cost method of accounting for the costs of its oil and gas properties, (ii) amortizes such costs using the units of production method, and (iii) applies a quarterly full cost ceiling test. Adverse changes in conditions (primarily gas price declines) could result in permanent write-downs in the carrying value of oil and gas properties as well as non-cash charges to operations, but would not affect cash flows.

Estimates of Proved Oil and Gas Reserves. An independent petroleum engineer annually estimates approximately 60% of the company's proved reserves. The company estimates the remainder. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof. In addition, subsequent physical and economic factors such as the results of drilling, testing, production and product prices may justify revision of such estimates. Therefore, actual quantities, production timing, and the value of reserves may differ substantially from estimates. A reduction in proved reserves would result in an increase in depreciation, depletion and amortization ("DD&A") expense.

Estimates of Asset Retirement Obligations. In accordance with Statement of Financial Accounting Standards ("SFAS") No 143, the company makes estimates of future costs and the timing thereof in connection with recording its future obligations to plug and abandon wells. Estimated abandonment dates will be revised in the future based on changes to related economic lives, which vary with product prices and production costs. Estimated plugging costs may also be adjusted to reflect changing industry experience. Increases in operating costs and decreases in product prices would increase the estimated amount of the obligation and increase DD&A expense. Cash flows would not be affected until costs to plug and abandon were actually incurred.

Cautionary Statement Pursuant to Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

This Form 10-KSB 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 Form 10-KSB, other than statements of historical facts, address matters that the company reasonably expects, believes or anticipates will or may occur in the future. Such statements are subject to various assumptions, risks and uncertainties, many of which are beyond the control of the company. Investors are cautioned that any such statements are not guarantees of future performance and that actual results or developments may differ materially from those described in the forward-looking statements.

ITEM 7. FINANCIAL STATEMENTS

Index to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

October 31, 2004 and 2003

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2004	2003
Assets		
Current assets:		
Cash and cash equivalents	**$ 518,000**	$ 1,885,000
Short-term investments	**6,371,000**	4,778,000
Receivables:		
Trade	**1,019,000**	410,000
Accrued oil and gas sales	**2,051,000**	1,256,000
Other	**58,000**	234,000
Total current assets	**10,017,000**	8,563,000
Oil and gas properties, net, at cost, using full cost method:		
Unevaluated	**2,174,000**	2,075,000
Evaluated	**17,335,000**	11,986,000
Net oil and gas properties	**19,509,000**	14,061,000
Exclusive license agreement, net of amortization of $291,000 and $221,000	**408,000**	478,000
Other, net	**1,042,000**	470,000
	$ 30,976,000	$ 23,572,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 4,394,000**	$ 1,776,000
Income taxes payable	**12,000**	210,000
Total current liabilities	**4,406,000**	1,986,000
Deferred income taxes, net	**4,605,000**	3,358,000
Exclusive license obligation, less current obligations of $58,000 and $53,000	**297,000**	355,000
Asset retirement obligation	**748,000**	238,000
Commitments		
Stockholders' equity:		
Preferred stock, without par value, 5,000,000 shares authorized, none issued		
Common stock, $.10 par value, 20,000,000 shares authorized, 6,340,000 shares issued in 2004 and 4,334,000 issued in 2003	**634,000**	433,000
Capital in excess of par value	**12,463,000**	12,664,000
Retained earnings net of $6,277,000 related to 20% stock dividend in 2003	**8,712,000**	5,062,000
Accumulated other comprehensive income (loss)	**(437,000)**	180,000
Treasury stock, at cost, 303,000 shares in 2004, and 378,000 shares in 2003	**(452,000)**	(704,000)
Total stockholders' equity	**20,920,000**	17,635,000

	2004	2003
	$ 30,976,000	$ 23,572,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Three Years Ended October 31, 2004

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2004	2003	2002
Revenues:			
Oil and gas sales	**$ 9,367,000**	$ 7,494,000	$ 4,698,000
Operating	**604,000**	536,000	488,000
Investment income and other	**343,000**	461,000	172,000
	10,314,000	8,491,000	5,358,000
Costs and expenses:			
Oil and gas production	**2,075,000**	1,608,000	1,291,000
Depreciation, depletion and amortization	**1,747,000**	1,333,000	1,202,000
General and administrative	**1,383,000**	1,257,000	1,060,000
Interest	**39,000**	46,000	49,000
	5,244,000	4,244,000	3,602,000
Income before income taxes and cumulative effect of accounting change	**5,070,000**	4,247,000	1,756,000
Income taxes	**(1,420,000)**	(1,189,000)	(474,000)
Income before cumulative effect of accounting change	**3,650,000**	3,058,000	1,282,000
Cumulative effect of change in accounting principle		72,000	
Net income	**$ 3,650,000**	$ 3,130,000	$ 1,282,000
Basic income per share before accounting change	**$ .61**	$ .52	$ .22
Cumulative effect of change in accounting principle		.01	
Basic income per share	**$ .61**	$ .53	$ .22
Diluted income per share before accounting change	**$ .59**	$ .51	$ .21
Cumulative effect of change in accounting principle		.01	
Diluted income per share	**$ .59**	$ .52	$ .21

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Three Years Ended October 31, 2004

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock Shares	Common Stock Amount	Capital In Excess Of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Stockholders' Equity
Balances, October 31, 2001	3,678,000	$ 368,000	$ 6,452,000	$ 6,927,000	$ 14,000	$ (918,000)	$ 12,843,000
Comprehensive income:							
Net income				1,282,000			1,282,000
Other comprehensive income, net of tax: Change in fair value of derivatives					23,000		23,000
Comprehensive income							1,305,000
Purchase of treasury stock						(71,000)	(71,000)
Exercise of stock options						230,000	230,000
Balances, October 31, 2002	3,678,000	368,000	6,452,000	8,209,000	37,000	(759,000)	14,307,000
Comprehensive income:							
Net income				3,130,000			3,130,000
Other comprehensive income, net of tax: Change in fair value of derivatives					143,000		143,000
Comprehensive income							3,273,000
20% stock dividend	656,000	65,000	6,212,000	(6,277,000)			
Purchase of treasury stock						(1,000)	(1,000)
Exercise of stock options						56,000	56,000
Balances, October 31, 2003	4,334,000	433,000	12,664,000	5,062,000	180,000	(704,000)	17,635,000
Comprehensive income:							
Net income				3,650,000			3,650,000
Other comprehensive income (loss), net of tax: Change in fair value of derivatives					(617,000)		(617,000)
Comprehensive income							3,033,000
3-for-2 stock split	2,006,000	201,000	(201,000)				
Purchase of treasury stock						(39,000)	(39,000)
Exercise of stock options						291,000	291,000
Balances, October 31, 2004	**6,340,000**	**$ 634,000**	**$ 12,463,000**	**$ 8,712,000**	**$ (437,000)**	**$ (452,000)**	**$ 20,920,000**

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Years Ended October 31, 2004

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2004	2003	2002
Cash flows from operating activities:			
Net income	**$ 3,650,000**	$ 3,130,000	$ 1,282,000
Non-cash expenses included in net income:			
Depreciation, depletion and amortization	**1,747,000**	1,333,000	1,202,000
Deferred income taxes	**1,496,000**	1,016,000	379,000
Cumulative effect of change in accounting principle		(72,000)	
Other	**34,000**	6,000	7,000
Changes in operating assets and liabilities:			
Proceeds from short-term investments	**944,000**	5,261,000	4,836,000
Purchase of short-term investments	**(2,537,000)**	(4,453,000)	(5,139,000)
Trade receivables	**(609,000)**	167,000	(260,000)
Accrued oil and gas sales	**(795,000)**	(721,000)	(168,000)
Other current assets	**95,000**	299,000	(126,000)
Accounts payable and accrued costs and expenses	**791,000**	(236,000)	603,000
Income taxes payable	**(198,000)**	161,000	(61,000)
Net cash provided by operating activities	**4,618,000**	5,891,000	2,555,000
Cash flows from investing activities:			
Additions to oil and gas properties (net of $885,000 in 2004 and $446,000 in 2003 included primarily in accounts payable)	**(5,671,000)**	(5,520,000)	(2,464,000)
Proceeds from sale of oil and gas properties	**317,000**	526,000	376,000
Other	**(825,000)**	(338,000)	(77,000)
Net cash used in investing activities	**(6,179,000)**	(5,332,000)	(2,165,000)
Cash flows from financing activities:			
Proceeds from exercise of stock options	**291,000**	56,000	230,000
Purchase of treasury stock	**(39,000)**	(1,000)	(71,000)
Principal payment on exclusive license obligation	**(58,000)**	(53,000)	(44,000)
Net cash provided by financing activities	**194,000**	2,000	115,000
Increase (decrease) in cash and cash equivalents	**(1,367,000)**	561,000	505,000
Cash and cash equivalents:			
Beginning of year	**1,885,000**	1,324,000	819,000
End of year	**$ 518,000**	$ 1,885,000	$ 1,324,000
Supplemental Cash Flow Information:			
Cash paid for income taxes	$ 194,000	$	$ 70,000
Cash paid for interest	$ 41,000	$ 46,000	$ 50,000

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
October 31, 2004

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Presentation

The consolidated financial statements include the accounts of CREDO Petroleum Corporation and its wholly owned subsidiaries (the "company"). The company engages in oil and gas acquisition, exploration, development and production activities in the United States. Certain operations are conducted through limited partnerships and limited liability companies which, as general partner or member company, the company manages and controls. The company's interests in these entities are combined on the proportionate share basis in accordance with accepted industry practice. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to prior year amounts with no effect on net income. 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 highly liquid investments with original maturities of three months or less. At October 31, 2004, approximately 60% of short-term investments are mutual funds. Other short-term investments consist primarily of professionally managed limited partnerships which provide readily determinable market values and short-term liquidity. The partnerships are invested primarily in financial instruments. Unrealized gains on limited partnerships are not significant. Short-term investments are classified as "trading" and are stated at fair value with realized and unrealized gains and losses immediately recognized.

Oil and Gas Properties

The company follows the full cost method of accounting for its oil and gas operations. Under this method all costs incurred in the acquisition, exploration, and development of oil and gas properties are capitalized in one cost center, including certain internal costs directly associated with such activities which totaled $200,000 in 2004, 2003 and 2002. Proceeds from sales of oil and gas properties are credited to the cost center with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

If capitalized costs, less related accumulated DD&A and deferred income taxes, exceed the "full cost ceiling," the excess is expensed in the period such excess occurs. The full cost ceiling includes an estimated discounted value of future net revenues attributable to proved reserves using current product prices and operating costs less outflows associated with settling asset retirement obligation accrued on the balance sheet in accordance with SFAS No. 143, and an estimate of the value of unproved properties. Costs of oil and gas properties, less estimated salvage values of lease and well equipment which are included in the cost center, are amortized using the units of production method. The company's composite depreciation, depletion and amortization ("DD&A") rate per equivalent barrel produced was $5.03 in 2004, $4.41 in 2003 and $4.27 in 2002.

Unevaluated properties consist primarily of lease acquisition and maintenance costs. Evaluation normally takes three to five years. Unevaluated property costs of $742,000 and $829,000 were incurred in 2004 and 2003, respectively.

Natural Gas Price Hedging

The company periodically hedges the price of its estimated natural gas production when the potential for significant downward price movement is anticipated. Hedging transactions take the form of forward, or "short," selling in the NYMEX futures market, and are closed by purchasing offsetting "long" positions. Such hedges, which are accounted for as cash flow hedges, do not exceed estimated production volumes, are expected to have reasonable correlation between price movements in the futures market and the cash markets where the company's production is located, and are authorized by the company's Board of Directors. Hedges are expected to be closed as related production occurs but may be closed earlier if the anticipated downward price movement occurs or if the company believes that the potential for such movement has abated.

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had after tax hedging losses of $516,000 in 2004 and $66,000 in 2003, and after tax hedging gains of $369,000 in 2002. The company has recorded in other comprehensive income net deferred losses of approximately $437,000 (after tax) related to natural gas hedging transactions of which losses of $112,000 were realized and $325,000 were unrealized. Any hedge ineffectiveness is immediately recognized in gas sales. At October 31, 2004, the company's open hedge position totaled 430,000 Mcf covering the months of December 2004 through June 2005. The hedge represented approximately 40% of the company's estimated gas production for those months. December hedges totaling 70,000 Mcf are swap contracts at an average price of $6.39. January through March hedges are collars with an average $6.12 floor and a $7.85 ceiling totaling 180,000 Mcf. April through June 2005 hedges are collars with a $5.50 floor and a $6.75 ceiling covering 180,000 Mcf.

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 gas reserve quantities and the related present value of estimated future net cash flows therefrom.

Stock-Based Compensation

In December 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 148, "Accounting for Stock-Based Compensation Transition and Disclosure, an amendment of SFAS No. 123." Among other provisions, the statement amends the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation." Under current accounting rules the company elected to account for its stock-based employee compensation under the intrinsic value method established by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."

No options were granted in 2004. The average fair value of each option granted was $5.66 in 2003 and $3.75 in 2002. All options were granted with an exercise price equal to the market price on the date of grant. The fair value was estimated on the date of grant using the Black-Scholes option-pricing model with an expected average volatility of 52% in 2003 and 53% in 2002, a risk-free interest rate of 3% in 2003 and 4% in 2002, no expected dividends, and average expected terms of five years.

If compensation expense had been determined in accordance with the provisions of SFAS No. 123, the company's net income and per share amounts would have been reported as follows:

Years Ended October 31	2004	2003	2002
Net income as reported	$ 3,650,000	$ 3,130,000	$ 1,282,000
Pro forma stock compensation expense, net of tax	(282,000)	(428,000)	(103,000)
Pro forma net income	$ 3,368,000	$ 2,702,000	$ 1,179,000
Basic net income per share:			
As reported	$ 0.61	$ 0.53	$ 0.22
Pro forma	$ 0.56	$ 0.46	$ 0.20
Diluted net income per share:			
As reported	$ 0.59	$ 0.52	$ 0.21
Pro forma	$ 0.54	$ 0.45	0.20

Per Share Amounts

Basic income per share is computed using the weighted average number of shares outstanding. Diluted income per share reflects the potential dilution that would occur if stock options were exercised using the average market price for the company's stock for the period. Total potential dilutive shares based on options outstanding at October 31, 2004 were 377,250. The assumed exercise of stock options would increase the weighted average shares outstanding from 6,024,000 to 6,188,000 in 2004, 5,913,000 to 6,028,000 in 2003 and 5,841,000 to 5,968,000 in 2002. Shares outstanding for 2003 and 2002 have been adjusted to reflect a 3-for-2 stock split effective April 5, 2004 and a 20% stock dividend effective April 2, 2003.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The company adopted SFAS No. 143 on November 1, 2002 and recorded a cumulative effect of a change in accounting principle on prior years of $72,000 (net of taxes of $28,000).

The company's asset retirement obligations arise from the plugging and abandonment liabilities for its oil and gas wells. The following is a reconciliation of the company's asset retirement obligations for the years ended October 31, 2004 and 2003.

	2004	2003
Asset retirement obligation beginning of period	$ 238,000	$
Liability from SFAS 143 adoption		179,000
Accretion expense	(10,000)	(7,000)
Obligations incurred	23,000	25,000
Obligations settled	(6,000)	
Change in estimate	503,000	41,000
Asset retirement obligation-end of period	$ 748,000	$ 238,000

Recently Issued Accounting Standards

In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment," which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation. SFAS No. 123(R) is effective for public companies for interim or annual periods beginning after June 15, 2005, supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows.

SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The new standard will be effective for the company, beginning August 1, 2005. The company has not yet completed their evaluation but expects the adoption to have an effect on the financial statements similar to the pro-forma effects reported above.

(2) COMMON STOCK AND PREFERRED STOCK

The company has authorized 5,000,000 shares of preferred stock which may be issued in series and with preferences as determined by the company's Board of Directors. Approximately 100,000 shares of the company's authorized but unissued preferred stock have been reserved for issuance pursuant to the provisions of the company's Shareholders' Rights Plan.

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

On March 19, 2003, the company declared a 20% stock dividend to shareholders of record on April 2, 2003. On April 23, 2003, the company issued 656,000 shares of common stock in conjunction with this dividend. Accordingly, the fair value based on the quoted market price of the additional shares issued of $6,277,000 was charged to retained earnings and credited to common stock and capital in excess of par value. Cash payments were made to shareholders in lieu of fractional shares. The basic and diluted weighted average number of shares outstanding and net income per share information for all prior reporting periods have been adjusted to reflect the effects of the 2004 stock split and the 2003 stock dividend.

The company's 1997 Stock Option Plan (the "Plan"), as amended and restated effective October 25, 2001, authorizes the granting of incentive and nonqualified options to purchase shares of the company's common stock. The Plan is administered by the Board of Directors which determines the terms pursuant to which any option is granted. The Plan provides that upon a change in control of the company, options then outstanding will immediately vest and the company will take such actions as are necessary to make all shares subject to options immediately salable and transferable. Plan activity is set forth below and has been adjusted for the 3-for-2 stock split in 2004 and 20% stock dividend in 2003.

Years Ended October 31	**2004**		**2003 Adjusted**		**2002 Adjusted**	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**
Outstanding at beginning of year	**484,470**	**$ 7.11**	172,620	$ 2.81	531,000	$ 2.03
Granted			369,750	8.67	27,000	4.64
Exercised	**(107,220)**	**2.71**	(30,150)	1.88	(205,380)	1.12
Cancelled or forfeited			(27,750)	6.83	(180,000)	2.71
Outstanding at end of year	**377,250**	**$ 8.37**	484,470	$ 7.11	172,620	$ 2.81

Options are exercisable at weighted average exercise prices as follows: 178,032 in 2004 at $8.33; 108,657 in 2005 at $8.44; 52,030 in 2006 at $7.94; and 38,531 in 2007 at $8.93. Options expire with weighted average exercise prices as follows: 27,000 in 2007 at $4.64, 27,000 in 2008 at $5.58,and 323,250 in 2013 at $8.91. The weighted average remaining contractual life of options outstanding at October 31, 2004 is 7.8 years.

(3) COMMITMENTS

The company leases office facilities under an operating lease agreement which expires May 1, 2006. The lease agreement requires payments of $43,000 in 2005 and $22,000 in 2006. Total rental expense was $77,000 in 2004, $73,000 in 2003, and $73,000 in 2002. The company has no capital leases and no other operating lease commitments.

(4) INCOME TAXES

The company follows the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. At October 31, 2004, the company had $1,576,000 of statutory depletion carry forward for tax return purposes and $831,000 for financial statement purposes.

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

Years Ended October 31	2004	2003	2002
Current	**$ 114,000**	$ 173,000	$ 95,000
Deferred	**1,306,000**	1,016,000	379,000
	$ 1,420,000	$ 1,189,000	$ 474,000

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

Years Ended October 31	2004	2003	2002
Federal statutory income tax rate	**34%**	34%	34%
State income taxes	**2**	2	2
Percentage depletion	**(8)**	(8)	(9)
	28%	28%	27%

The principal sources of temporary differences resulting in deferred tax assets and tax liabilities at October 31, 2004 and 2003 are as follows:

October 31	2004	2003
Deferred tax assets:		
Gain on property sales	**$ 505,000**	$ 452,000
Total deferred tax assets	**505,000**	452,000
Deferred tax liabilities:		
Intangible drilling, leasehold and other exploration costs capitalized for financial reporting purposes but deducted for tax purposes	**(4,714,000)**	(3,438,000)
State taxes and other	**(396,000)**	(372,000)
Total deferred tax liabilities	**(5,110,000)**	(3,810,000)
Net deferred tax liability	**$ (4,605,000)**	$ (3,358,000)

(5) EXCLUSIVE LICENSE AGREEMENT OBLIGATION

On September 1, 2000, the company acquired an unrestricted, exclusive license for patented technology. The initial license term was ten years and includes an option to extend the term to the remaining life of the patents. The licensor will receive a net 8.3% carried interest in any installation of the technology. The license purchase price was $1,115,000, of which $590,000 has been paid. The balance, which is due in five remaining annual increments of $105,000, is recorded at 10% present value. The related assets are being amortized over 10 years on a straight-line basis. If the option to extend the license after the initial ten-year term is exercised, the cost will be $94,000 per year to the expiration of the last patent.

(6) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

October 31	2004	2003	2002
Unproved properties not being amortized	**$ 2,174,000**	$ 2,075,000	$ 1,690,000
Properties being amortized	**30,072,000**	23,082,000	18,027,000
Accumulated depreciation, depletion and amortization	**(12,737,000)**	(11,096,000)	(10,040,000)