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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2005

Commission File Number 0-9120

THE EXPLORATION COMPANY OF DELAWARE, INC.
(Exact name of Registrant as specified in its charter)

Delaware	**84-0793089**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
500 North Loop 1604 East, Suite 250, San Antonio, Texas	**78232**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(210) 496-5300**

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

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, par value $0.01 per share**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ 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.
Yes ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act).
Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☑

As of June 30, 2005, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $102.9 million based on the closing price of $4.32 per share as reported on the NASDAQ Capital Market on that date.

The number of shares outstanding of the registrant's Common Stock as of March 3, 2006, was 29,833,230.

Documents Incorporated by Reference: Portions of the Company's Proxy Statement for the Annual Shareholders' Meeting, to be held on May 12, 2006 are incorporated by reference into Items 10, 11, 12 and 14 of Part III of this filing.

INDEX AND CROSS REFERENCE SHEET

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Statements in this Form 10-K which are not historical, including statements regarding TXCO's or management's intentions, hopes, beliefs, expectations, representations, projections, estimations, plans or predictions of the future, are forwarding-looking statements and are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Such statements include those relating to expected drilling plans, including the timing, category, number, depth, cost and/or success of wells to be drilled, expected geological formations or the availability of specific services or technologies. It is important to note that actual results may differ materially from the results predicted in any such forward-looking statements. Investors are cautioned that all forward-looking statements involve risks and uncertainty. These risks and uncertainties include: the costs and accidental risks inherent in exploring and developing new oil and natural gas reserves, the price for which such reserves and production can be sold, environmental concerns affecting the drilling of oil and natural gas wells, impairment of oil and gas properties due to depletion or other causes, the uncertainties inherent in estimating quantities of proved reserves and cash flows, as well as general market conditions, competition and pricing. Please refer to the Risk Factors discussion in Part I, Item 1A for additional information.

PART I

ITEM 1. BUSINESS

GENERAL

The Exploration Company was incorporated in the State of Colorado in 1979 and reincorporated in the State of Delaware in 1999, becoming The Exploration Company of Delaware, Inc. Our trading symbol on the Nasdaq Capital Market[SM] is TXCO. Unless the context requires otherwise, when we refer to "TXCO", "the Company", "we", "us" and "our", we are describing The Exploration Company of Delaware, Inc. Our contact information is (1) by mail: 500 N. Loop 1604 East, Suite 250, San Antonio, Texas 78232, (2) by phone: 210/496-5300. Our Web site is www.txco.com.

We file annual, quarterly, and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). All of these reports are available on our Web site under the link "SEC Filings" on the "Investor Relations" menu, as soon as reasonably practicable after we electronically file them with or furnish them to the SEC. Forms 3, 4 and 5 may also be accessed from the "Insider Reports" link on the "Governance" menu. You may obtain free of charge a copy of the reports provided to the SEC by written request to the Corporate Secretary at the address above.

Also under the "Governance" menu, you can access our corporate governance documents, including our Code of Conduct, and charters for the Governance and Nominating, and Audit Committees of our Board of Directors. The "Investor Relations" menu also contains links to recent presentations, news releases and reconciliations of non-GAAP items.

As of December 31, 2005, we employed 49 full-time employees including management. We believe our relations with our employees are good. None of our employees are covered by union contracts.

LONG-TERM STRATEGY

Our primary business operation is exploration, development, and production of onshore domestic oil and gas reserves. We have a consistent record of long-term growth in proved oil and gas reserves, leasehold acreage position, production and cash flow through our established exploration and development programs. Our business strategy is to build shareholder value by acquiring undeveloped mineral interests and internally developing a multi-year drilling inventory through the use of advanced technologies, such as 3-D seismic and horizontal drilling. We strive to discover, develop and/or acquire more oil and gas reserves than we produce each year from these internally developed prospects. As opportunities arise, we may selectively participate with industry partners in prospects generated internally as well as by other parties. We attempt to maximize the value of our technical expertise by contributing our geological, geophysical and operational core competencies through joint ventures or other forms of strategic alliances with well capitalized industry partners in exchange for carried interests in seismic acquisitions, leasehold purchases and/or wells to be drilled. From time to time, we offer portions of our developed and undeveloped mineral interests for sale. We finance our activities through internally generated operating cash flows, as well as debt financing and equity offerings, or sale of interests in properties when favorable terms or opportunities are available.

Management's ongoing strategy for improved shareholder value includes maintaining a focus on our core business of oil and gas exploration and production. This strategy allows us to attract recognized industry partners, expand our core area leasehold acreage, and increase our 3-D seismic database and interpretative skill set. This strategy, coupled with our drill bit success, allows us to grow our reserve base while maintaining a conservative debt profile. We have remained focused on the Maverick Basin and have successfully established a multi-year portfolio of drilling targets within our core area. To support our growing asset base in the Maverick Basin, we acquired a 69-mile natural gas gathering system in 2002, which we expanded to more than 90 miles of pipeline by 2005. The gathering system assures our access to North American markets, and enables us to realize higher prices for our natural gas and better share in proceeds from extraction of natural gas liquids.

Our established operating strategy includes the pursuit of multiple growth opportunities and diversified exploration targets within our core area of operations. We are well positioned to pursue new oil and gas reserves and expand our production base due to aggressively expanding our surrounding lease holdings where geology indicates the likely continuation of known or prospective oil and gas producing formations. The Maverick Basin offers a diversity of hydrocarbon-bearing horizons.

RECENT DEVELOPMENTS

2005 Drilling Activity Summary: We participated in drilling a total of 52 gross wells during 2005. Maverick Basin wells totaled 51, including five re-entries, while one well was drilled in the Williston Basin. Thirteen of the Maverick Basin wells were sold as part of our Asset Sale during the third quarter of 2005 described below. Of the remaining 39 total wells, 24 have been placed on production through February 2006, while 15 remain in various stages of completion. There were no dry holes. Completed Maverick Basin wells include 21 producing oil and two producing natural gas, while the one Williston Basin well drilled is producing oil. A total of 54 wells remained pending completion at year-end 2005, including wells remaining from prior years (see the "In Progress Recap" for further information). Three of the five re-entries resulted in producing well completions (one oil and two natural gas).

Reserve Growth: We continued our ongoing trend of annual reserve growth in 2005 by recording net proved reserve additions of 1.5 billion cubic feet equivalent ("Bcfe"). Combined with annual production of 4.6 Bcfe and reserves sold of 1.4 Bcfe, our gross reserve additions for the year were 7.5 Bcfe. Estimated year-end proved oil and gas reserves reached a record 39.4 Bcfe, a 4.0% increase above the 37.9 Bcfe at year-end 2004. We achieved a 161% all-source reserve replacement rate in 2005.

This expansion of our oil and gas reserves and production base was achieved by pursuing exploration in seven distinct Maverick Basin plays, ranging from the San Miguel to the Glen Rose formations -- all above 7,000 feet. Exploration and development targets for 2006, presented in descending depth order, include:

- expanding waterflood oil production from the San Miguel interval;
- expanding oil and gas production from Georgetown horizontal wells;
- continued horizontal and vertical drilling for Glen Rose shoal and reef gas intervals;
- additional Comanche Ranch lease horizontal wells targeting Glen Rose porosity oil production; and
- vertical wells targeting gas from the Pearsall and Sligo formations.

Each of these high-impact exploration and development targets has potential to establish meaningful additions to our oil and gas production and proved reserves, along with significant numbers of new, proved undeveloped, lower-risk drilling locations.

2006 Capital Expenditures Budget: Should our exploration and development plans progress as projected, we expect continued growth of our oil and gas reserves and production levels in 2006. We established a range of $40 million to $50 million for our 2006 capital expenditure budget ("CAPEX"), with approximately 95% earmarked for drilling 53 new wells and four re-entries targeting four primary horizons. The remaining $2.1 million will go toward seismic acquisition, lease extensions and water injection well conversions. CAPEX may expand or contract based on drilling results, operational developments, unanticipated transaction opportunities, market conditions, commodity price fluctuations and working capital availability. Based on our continued drilling success, we expect to be profitable in 2006, and further expect to have sufficient working capital available from traditional sources, including cash flow from operations and borrowings from our reserve-based bank credit facility, as well as industry sources and equity markets, as needed. However, we retain our ability to adjust our capital expenditure program consistent with our available liquidity in order to continue to meet our ongoing operating and debt service obligations on a timely basis.

September 2005 Asset Sale: In December 2004, we retained Raymond James & Associates to assist in actively pursuing strategic alternatives designed to enhance shareholder value. As a result of this process, we entered into an $80 million purchase and sale agreement ("Asset Sale") in September 2005 for a portion of our interests in the Maverick Basin with EnCana Oil & Gas (USA) Inc. Proceeds from this sale of primarily undeveloped acreage were used to pay down debt on our credit facility, and retire our redeemable preferred stock and certain other obligations. Proceeds were also used to acquire an interest in the Marfa Basin that we hope to begin developing in the second half of 2006. The Asset Sale is further described in the section by that title in the Management's Discussion and Analysis section of this Annual Report on Form 10-K.

February 2005 Acquisition/Exchange: We acquired a 50% interest in more than 174,000 gross acres in Maverick, Dimmit, and Zavala counties. This additional acreage lies mostly contiguous, to the south and east of our existing lease block and is prospective for many of our active plays, including in descending depth order, the Escondido, Olmos Coals (CBM), San Miguel, Georgetown, Glen Rose, Pearsall, Sligo and Jurassic targets. We exchanged a 50% interest in shallow zones (to the base of the San Miguel formation) in certain of our Comanche and Chittim leases, and all depths in certain other Chittim leases, for the interest.

October 2005 Acquisition: We acquired all of the oil and gas leasehold working interest in all depths and formations underlying approximately 140,000 gross acres (approximately 135,000 net acres) of the Marfa Basin, located in the west Texas counties of Presidio and Brewster, primarily from Peacock Oil & Gas Properties, Ltd. ("Peacock") and Elton Smith ("Smith"). We paid for this new acreage with cash and issuance to Peacock and Smith of 450,000 shares of unregistered common stock of TXCO.

Subsequent Acquisition: On March 10, 2006, we closed on the purchase of a drilling rig and other personal property and equipment from Ada Energy Services, LLC. The consideration for the purchase was $4.3 million.

PRINCIPAL AREAS OF ACTIVITY

Oil and Gas Operations: During 2005, we expanded our Maverick Basin lease block to 656,000 contiguous acres. In addition, we spudded or re-entered a total of 51 wells in various horizons in the Maverick Basin, and one in the Williston Basin. These totals compared to 66 and 3, respectively, in 2004. Thirteen of the 2005 wells were sold to EnCana Oil & Gas (USA), Inc. ("EnCana") as part of the Asset Sale. The wells sold to EnCana included four each producing oil and natural gas, and five that were awaiting completion. Of the remaining 39 wells, 24 have been placed on production through February 2006, including 22 new oil wells in the Glen Rose, San Miguel, Georgetown, Edwards, Austin Chalk and Red River formations, and two re-entered gas wells were completed in the Georgetown formation.

The Maverick Basin drilling activity reflects our continued ability to generate working capital from healthy internal operating margins, and industry sources, allowing for expansion of our Texas-based lease acreage holdings and natural gas exploration and production activities. A one-time payment for the termination of hedges of natural gas, combined with increased income taxes after the Asset Sale, and a decrease in Maverick Basin natural gas production during 2005, resulted in a decline in net cash provided by operating activities to $6.3 million in 2005 from $16.4 million in 2004. See the table in the Sources and Uses section on page 23.

Our strategy remains focused on our core oil and natural gas producing properties and higher margin exploration activities in the Maverick Basin, while beginning to evaluate opportunities in our newly acquired Marfa Basin acreage. We continue to evaluate economic alternatives related to our remaining properties in the Williston Basin, including efforts to either locate suitable joint venture partners, farmout, or sell our interest in that basin.

Maverick Basin: At year-end 2005, we had an average working interest of over 85% on our Maverick Basin leasehold acreage. A large portion of this contiguous lease block is situated on the Chittim Anticline, a large regional geologic structure. Hydrocarbons have been found in at least 14 separate horizons along the structure including the Lower Glen Rose or Rodessa interval -- a carbonate formation that has produced billions of cubic feet of natural gas from patch reefs and shoals.

We utilize 3-D seismic survey data as an integral part of our interpretative methodology for the identification and evaluation of drilling prospects in most of our active plays. During 2005, we finalized a lease exchange program under which we acquired an additional 140 square miles of 3-D seismic data on the leases acquired early in the year. At year-end 2005 we had accumulated over 934 square miles of 3-D seismic data covering more than 90% of our 1,015-square-mile (equivalent to 650,000 acres) Maverick Basin lease block.

Our geologists and geophysicists have identified and mapped numerous geological formations at various depths on most of our lease block. This provides a growing, multi-year inventory of alternative drilling prospects for the ongoing evaluation of horizons known to be productive for oil and/or gas within and around our leases in the Maverick Basin. The active plays under ongoing evaluation by our engineers are described under the "Maverick Basin Plays" heading later in this section.

The following table contains details by formation in descending depth order for our approximate working interest ownership in some of our Maverick Basin projects budgeted for 2006:

		Working Interest Range
1	San Miguel Tar Sand Oil	50%
2	San Miguel - Oil Waterflood	100%
3	Georgetown - Oil	100%
4	Glen Rose - Oil Porosity Zone	50% to 100%
5	Glen Rose - Gas Shoals	48% to 75%
6	Pearsall/Sligo - Gas	12.5% to 50%

The expanding geophysical database, historical drilling results and the growing number of prospective formations targeted by our drilling programs with our partners reaffirmed our longstanding belief that our exploration and development possibilities on our growing Maverick Basin lease block remain very significant.

MAVERICK BASIN PLAYS

Glen Rose Oil: During 2005, we increased our interest in much of our non-operated, 130,000-acre Comanche prospect from 50% to 75.5%. We have a proprietary, 100-square mile, 3-D seismic survey that covers the western half of the Comanche prospect, including the Cinco Ranch lease on the western flank of the Comanche acreage. We, along with our partners, acquired and processed the entire 3-D survey several years ago, identifying numerous Glen Rose prospects. While the first well found a water-bearing reef, the second well became the discovery well for the Comanche Halsell (6500) field and tested at rates over 2,000 BOPD in 2002. That well targeted a prospect on the Comanche Ranch lease, which contained evidence of multiple Glen Rose prospects stacked over a previously unidentified structure. Initial drilling found no productive reefs, but discovered a highly fractured porosity interval.

After the first three years of development, production on the Comanche Ranch lease was spread over a 20 square-mile area. Forty-degree gravity oil is consistent throughout the entire area, which contains no gas. The partners' engineering staffs completed extensive reviews of the porosity intervals and our oil and water production profiles and determined that this is a strong water-drive reservoir. Additionally, seismic was integrated with the Comanche Halsell field production profile. The water, which is produced along with the oil, is disposed of at surface locations or trucked to disposal wells.

Only two wells were drilled on the Comanche Ranch during 2004 due to the restructuring of our operating partner. Activity picked up in 2005 with the successor to the restructuring with six new wells spudded along with one re-entry on the Comanche Ranch leases. Additionally, we extended the play into the adjacent Cage Ranch where we hold a 100% working interest (WI). We spudded 10 Glen Rose oil wells on the Cage Ranch and one on the Stone Ranch during 2005. Of the combined 18 wells drilled to the porosity zone, 11 were producing oil at year-end 2005, while seven remained in completion. Since year-end, one additional 2005 well has begun production.

Glen Rose oil sales for 2005 totaled 236,000 BO up from 141,000 BO during 2004. The combined number of wells drilled since the oil play's discovery in February 2002 stands at 46 through year-end 2005. Cumulative Glen Rose gross oil production since its discovery surpassed 2.4 million barrels of oil through February 2006. The project remains profitable and economics should improve as we and our partners better define the expansive play and perfect drilling techniques used to maximize the recovery of oil in this strong water-drive formation. Net proved reserves at December 31, 2005, for the Glen Rose oil porosity zone are estimated at 1.2 million BO, equivalent to 7.4 Bcfe, up from 745,000 BO (4.5 Bcfe) for the prior year. We believe that significant additional proved reserves will be established in the future.

We spudded two porosity wells thus far in 2006. One well currently awaits completion while one well continues drilling. Our 2006 CAPEX includes $21.2 million for 24 porosity wells.

Glen Rose Gas: In late 2001, we announced the start of a horizontal Glen Rose shoal gas play on a portion of our Chittim lease. Our geologists analyzed a large carbonate shoal (or carbonate "sand" bar) located within the Glen Rose interval. The Chittim 1-141, the first well completed in this program, went on production in 2001 at a rate of 2.0 MMcfd, has cumulative production through February 2006 of over 1.0 Bcf, and is still producing about 150 Mcfd. As provided under our farm-in agreement with AROC-Texas Inc., covering this portion of the Chittim lease, we drill and complete these horizontal Glen Rose shoal wells and AROC operates them.

Our horizontal Glen Rose shoal drilling program produced a string of 29 successful horizontal gas well completions through 2004. We spudded one shoal well during 2005 and it awaits completion. We spudded two new Glen Rose reef wells during 2005, with one awaiting completion into another zone, and one recompleted into the Georgetown formation and producing oil. Glen Rose gas sales for 2005 totaled 1.4 Bcf down from 1.7 Bcf during 2004. The field produced 10.4 Bcf since horizontal drilling techniques were applied. At December 31, 2005, net proved gas reserves for Glen Rose were estimated at 9.2 Bcfe, down from 11.2 Bcfe for the prior year. Plans for 2006 includes $1.5 million for drilling four Glen Rose shoal or reef wells.

Georgetown: During 2005, we spudded 12 new Georgetown wells and re-entered four wells, in addition to one Georgetown completion originally targeting Glen Rose reefs, as compared to 26 Georgetown wells drilled or re-entered in 2004. Ten of the wells drilled in 2005 were later transferred to EnCana as part of the Asset Sale. Of the retained Georgetown wells, two new wells and one re-entry are producing oil, while two of the re-entered wells are producing gas. One re-entry and one new well are in completion. Georgetown gas sales for 2005 totaled 728 MMcf, down from 1.1 Bcf during 2004 due to the Asset Sale in the third quarter of 2005, while Georgetown oil sales increased to 49,800 BO from 41,324 BO in 2004. The current 2006 CAPEX budget includes $6.6 million for 10 new wells. We spudded one horizontal Georgetown well in January 2006 that began production in February.

We began using coherency processing to more accurately predict the location of formation faults and fractures in this field in late 2003. The Georgetown is a fractured reservoir, which makes it difficult to predict the type and quantity of ultimate reserves for each well, as such reservoirs typically have hyperbolic decline curves with high initial production rates that rapidly fall to lower, sustained rates. Georgetown proved reserve estimates decreased to 0.6 Bcfe from 7.5 Bcfe at year-end 2004 due to the sale of our interest in this formation across our southern leasehold block in September 2005.

San Miguel Waterflood: In 2002, we acquired the Pena Creek oil field in Dimmit County, Texas, which included 94 producing oil wells, 94 injection wells and 28 shut-in wells, and we completed a 3-D seismic survey covering the field and surrounding acreage. We also completed an extensive geological, engineering and 3-D seismic review, including the review of historic well data acquired with the property. These evaluations enabled us to identify bypassed infill San Miguel oil reserves, establishing more than 120 potential infill locations to date, with further potential to establish additional infill locations as warranted by ongoing drilling results. We expect additional oil recovery from planned revamping of injection well configuration.

During 2005, we drilled six infill wells targeting bypassed reserves, successfully completing five of those wells, while one awaits completion. We successfully completed all 10 wells spudded during 2004. San Miguel natural gas sales for 2005 increased to 5.1 MMcf, from 3.0 MMcf during 2004, while oil sales declined to 78,517 BO from 93,979 BO for the same periods. We no longer have San Miguel natural gas due to the September 2005 sale. Net proved reserves at year-end for this field were estimated at 3.6 million barrels, equivalent to 21.4 Bcfe, up from 2.2 million barrels (13 Bcfe) at year-end 2004. The 10,000-acre Pena Creek prospect is contiguous to our Comanche Ranch lease. The 2006 CAPEX budget includes $3.0 million for 10 new wells in the San Miguel waterflood.

Pearsall: Our 2006 CAPEX budget includes $8.0 million for drilling eight new wells in the Pearsall formation on our Chittim lease block in partnership with EnCana. This represents our first major investment in this promising formation that covers a large portion of our Maverick Basin acreage. The Pearsall is an over-pressured shale play. During 2004, we recompleted one well into the Pearsall formation that continues to produce about 44 Mcf per day. No wells were drilled in this formation during 2005.

Coalbed Methane (CBM): During 2005 we sold our interest in our CBM wells in the "Sacatosa (CBM Olmos) Field". We initially sold 50% of our interest as part of the February 2005 asset acquisition/exchange. Our remaining interests in these wells were sold as part of the Asset Sale in September 2005. We retain approximately 100,000 acres that are prospective for CBM.

Tar Sands: The San Miguel Tar Sand feature ("Tar Sands") is prospective under our existing Maverick Basin acreage. Literature prepared for the United States Geological Survey has established the Maverick Basin as the single largest deposit of Tar Sands in the State of Texas with 2 to 4 billion barrels of oil in place. Conoco and Mobil did pilot projects on the San Miguel Tar Sand in the late 1970's and early 1980's and achieved recoveries of over 50% with the use of steam injection. These Tar Sands are much like those found in Cold Lake Field in Canada. In February of 2005 we entered into a Participation Agreement between Pearl Exploration and Production, Ltd. (TSX Venture: "PXX") ("Pearl"), formerly known as Newmex Minerals, Inc. While we are the operator with a 50% working interest, we are drawing on Pearl's technical expertise with similar projects in Canada. The Participation Agreement includes an Area of Mutual Interest that covers approximately 33,000 acres of our leasehold and calls for the drilling of three pilot wells at no cost to us. To date, the initial pilot well has been drilled and completed and a second well has been drilled and is currently awaiting completion. In addition, construction of the steam facility is currently in progress and we expect construction to be complete in April of 2006. We were issued permits from the Texas Railroad Commission ("TRRC") on February 23, 2006 to inject steam into the formation and we expect to begin the steam injection process in May of 2006. If the results from the pilot wells are successful, we may begin the design and construction of a full field development in the second half of 2006, which would require us to make additional capital expenditures. Our initial 2006 CAPEX budget includes $300,000 for one San Miguel Tar Sand well.

Other Plays: During 2005, we drilled six wells in other Maverick Basin formations: four in the Austin Chalk formation, and one each in the James Lime and Edwards formations. Three of the Austin Chalk wells were later transferred as part of the Asset Sale. Of the remaining three wells, one is producing oil and two are awaiting completion. The initial 2006 CAPEX budget does not include funds for drilling in any of these formations.

We expect economic development of the shallow Olmos sands, with depths ranging from approximately 700 to 1,900 feet, to accelerate as pipeline infrastructure grows along with the development of gas production in the immediate area from other formations.

MARFA BASIN

In October 2005, we acquired a 100% working interest in 140,000 gross acres (135,000 net acres) in the Marfa Basin. This basin is located approximately 200 miles northwest of our Maverick Basin leases. It is an underexplored area along the Ouachita Overthrust that is prospective for the Barnett and Woodford Shales. We are seeking a 50% partner to join us in the exploration and development of this basin. We plan to expand the CAPEX budget to include this effort when our partner is determined.

WILLISTON BASIN

Through 2005, we continued to evaluate all of our Williston Basin lease obligations, making lease extension payments on a selective basis, emphasizing those leases with particular geologic attributes or with adequate remaining primary lease terms. Consistent with our strategy to focus exploration efforts and resources on the development of our core producing area in Texas, we maintained marketing efforts offering our remaining Williston Basin holdings to other exploration companies with a focus on that area. At December 31, 2005, we retained approximately 83,000 net acres in the Williston Basin**.**

During 2005, we participated in the drilling of one new well (3.125% WI) in the Red River formation that is currently producing oil. In 2004 we participated in one new well and two re-entries in this formation. Our 2005 net sales for the Williston Basin totaled 31,232 BO and 58 MMcf, as compared to 42,314 BO and 31 MMcf in 2004. No funds have been included in the 2006 CAPEX for drilling in this basin.

PRINCIPAL PRODUCTS AND COMPETITION

Our principal products are crude oil and natural gas. The production and marketing of oil and gas are affected by a number of factors beyond our control, the effects of which we cannot accurately predict. These factors include crude oil imports, actions by foreign oil-producing nations, the availability of adequate pipeline and other transportation facilities, the marketing of competitive fuels and other matters affecting the availability of a ready market, such as fluctuating supply and demand. Generally, we sell all of our oil and gas under short-term contracts that can be terminated with 30 days notice, or less. None of our production was sold under long-term contracts with specific purchasers during 2004 or 2005. Consequently, we were able to market our oil and gas production to the highest bidder each month.

At management's discretion, we may participate in fixed-price contracts for a portion of our physical gas production when attractive opportunities are available. From time to time, we enter into derivative contracts to reduce exposure from price fluctuations and provide a more predictable cash flow stream. All such derivatives call for financial settlement rather than physical settlement. These derivatives are discussed further in Item 7A.

We operate and direct the drilling of oil and gas wells and also participate in non-operated wells. As operator, we contract service companies, such as drilling contractors, cementing contractors, etc., for specific tasks. In some non-operated wells, we participate as an overriding royalty interest owner.

During 2005, four purchasers of our oil and gas production and other natural gas sales accounted for 17%, 14%, 11% and 11% of total revenues. We believe that alternative purchasers could be found for such production at comparable prices if any of these major customers declined to purchase future production.

The oil and gas industry is highly competitive in the search for and development of oil and gas reserves. We compete with a substantial number of major integrated oil companies and other companies having significantly greater financial resources and manpower than we do. These competitors, having greater financial resources, have a greater ability to bear the economic risks inherent in all phases of this industry. In addition, unlike us, many competitors produce large volumes of crude oil that may be used in connection with their operations. These companies also possess substantially larger technical staffs, which puts us at a significant competitive disadvantage compared to others in the industry.

GENERAL REGULATIONS

Both state and federal authorities regulate the extraction, production, transportation, and sale of oil, gas, and minerals. The executive and legislative branches of government at both the state and federal levels have periodically proposed and considered proposals for establishment of controls on alternative fuels, energy conservation, environmental protection, taxation of crude oil imports, limitation of crude oil imports, as well as various other related programs. If any proposals relating to the above subjects were to be enacted, we can not predict what effect, if any, implementation of such proposals would have upon our operations. A listing of the more significant current state and federal statutory authority for regulation of our current operations and business are provided below.

Federal Regulatory Controls

Historically, the transportation and sale of natural gas in interstate commerce have been regulated by the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA") and associated regulations by the Federal Energy Regulatory Commission ("FERC"). The Natural Gas Wellhead Decontrol Act (the "Decontrol Act") removed, as of January 1, 1993, all remaining federal price controls from natural gas sold in "first sales." The FERC's jurisdiction over natural gas transportation was unaffected by the Decontrol Act.

In 1992, the FERC issued regulations requiring interstate pipelines to provide transportation, separate or "unbundled," from the pipelines' sales of gas (Order 636). This regulation fostered increased competition within all phases of the natural gas industry. In December 1992, the FERC issued Order 547, governing the issuance of blanket marketer sales certificates to all natural gas sellers other than interstate pipelines, and applying to non-first sales that remain subject to the FERC's NGA jurisdiction. These orders have fostered a competitive market for natural gas by giving natural gas purchasers access to multiple supply sources at market-driven prices. Order No. 547 increased competition in markets in which we sell our natural gas.

The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC and Congress will continue.

State Regulatory Controls

In each state where we conduct or contemplate conducting oil and gas activities, these activities are subject to various regulations. The regulations relate to the extraction, production, transportation and sale of oil and natural gas, the issuance of drilling permits, the methods of developing new production, the spacing and operation of wells, the conservation of oil and natural gas reservoirs and other similar aspects of oil and gas operations. In particular, the State of Texas (where we have conducted the majority of our oil and gas operations to date) regulates the rate of daily production allowable from both oil and gas wells on a market demand or conservation basis. At the present time, no significant portion of our production has been curtailed due to reduced allowables. We know of no proposed regulation that will significantly impede our operations.

Environmental Regulations

Our extraction, production and drilling operations are subject to environmental protection regulations established by federal, state, and local agencies. To the best of our knowledge, we believe that we are in compliance with the applicable environmental regulations established by the agencies with jurisdiction over our operations. We are acutely aware that the applicable environmental regulations currently in effect could have a material detrimental effect upon our earnings, capital expenditures, or prospects for profitability. Our competitors are subject to the same regulations and therefore, the existence of such regulations does not appear to have any material effect upon our position with respect to our competitors. The Texas Legislature has mandated a regulatory program for the management of hazardous wastes generated during crude oil and natural gas exploration and production, gas processing, oil and gas waste reclamation and transportation operations. The disposal of these wastes, as governed by the Railroad Commission of Texas, is becoming an increasing burden on the industry. Our leases in Montana, North Dakota and South Dakota are subject to similar environmental regulations including archeological and botanical surveys as most of the leases are on federal and state lands.

Federal and State Tax Considerations

Revenues from oil and gas production are subject to taxation by the state in which the production occurred. In Texas, the state receives a severance tax of 4.6% for oil production and 7.5% for gas production. North Dakota production taxes typically range from 9.0% to 11.5% while Montana's taxes range up to 17.2%. These high percentage state taxes can have a significant impact upon the economic viability of marginal wells that we may produce and require plugging of wells sooner than would be necessary in a less arduous taxing environment.

For Federal and State Income Taxes, we fully utilized all of our remaining tax net operating loss carryforwards, making our effective tax rate (federal and state) approximately 22%. Because these tax net operating losses have now been used, we expect our effective tax rate to approximate 37% in future years.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Our future success depends upon our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. As a result, we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We must do this even during periods of low oil and gas prices when it is difficult to raise the capital necessary to finance activities. Without successful exploration or acquisition activities, our reserves and revenues will decline. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities.

Oil and gas drilling is a high-risk activity.

Our future success will depend on the success of our drilling programs. In addition to the numerous operating risks described in more detail below, these activities involve the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including, but not limited to, the following:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- inability to comply with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

If we experience any of these problems, our ability to conduct operations could be adversely affected.

Factors beyond our control affect our ability to market oil and gas.

Our ability to market oil and gas from our wells depends upon numerous factors beyond our control. These factors include, but are not limited to, the following:

- the level of domestic production and imports of oil and gas;
- the proximity of gas production to gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effect of inclement weather;
- state and federal regulation of oil and gas marketing; and
- federal regulation of gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and gas or obtain favorable prices for our oil and gas could be adversely affected.

The marketability of our production may be dependent upon transportation facilities over which we have no control.

The marketability of our production depends in part upon the availability, proximity, and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities could harm our business. We deliver some of our oil and natural gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future.

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices could adversely affect our financial results.

Our future financial condition, results of operations and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future, especially given current world geopolitical conditions. Our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. This price volatility also affects the amount of our cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow or have outstanding under our bank credit facility is subject to semi-annual redeterminations. Oil prices are likely to affect us more than natural gas prices because approximately 70% of our proved reserves are oil. The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign oil and natural gas;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico;
- market uncertainty;
- political conditions in oil and natural gas producing regions, including the Middle East; and
- worldwide economic conditions.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements with any certainty. Also, oil and natural gas prices do not necessarily move in tandem. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect upon our financial condition, results of operations, oil and natural gas reserves and the carrying values of our oil and natural gas properties. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations or make planned expenditures.

Since the end of 1998, oil prices have gone from near historic low prices to historic highs. At the end of 1998, NYMEX oil prices were at historic lows of approximately $12.00 per Bbl, but have generally increased since that time, albeit with fluctuations. For 2005, NYMEX oil prices were high throughout the year, averaging over $56.00 per Bbl for 2005. During 2004 and 2005, the price we received for our heavier, sour crude oil did not correlate as well with NYMEX prices as it has historically. During 2002 and 2003, our average discount to NYMEX was $3.73 per Bbl and $3.60 per Bbl respectively. During 2004, this differential increased to $4.91 per Bbl for the year as a result of the price deterioration for heavier, sour crudes, and was even higher during the fourth quarter of 2004, averaging $6.48 per Bbl. During 2005, our oil differential averaged $6.33 per Bbl. While we attempt to obtain the best price for our crude in our marketing efforts, we cannot control these market price swings and are subject to the market volatility for this type of oil. These price differentials relative to NYMEX prices can have as much of an impact on our profitability as does the volatility in the NYMEX oil prices.

Natural gas prices have also experienced volatility during the last few years. During 1999 natural gas prices averaged approximately $2.35 per Mcf and, like crude oil, have generally trended upward since that time, although with significant fluctuations along the way. During 2004 NYMEX natural gas prices averaged $6.23 per MMBtu and in 2005, averaged $8.97 per MMBtu.

We may not be able to replace our reserves or generate cash flows if we are unable to raise capital.

We make, and will continue to make, substantial capital expenditures for the exploration, acquisition and production of oil and gas reserves. Historically, we have financed these expenditures primarily with cash generated by operations and proceeds from bank borrowings and equity financing. If our revenues or borrowing base decrease as a result of lower oil and gas prices, operating difficulties or declines in reserves, we may have limited ability to expend the capital necessary to undertake or complete future drilling programs. Additional debt or equity financing or cash generated by operations may not be available to meet these requirements.

We face strong competition from other energy companies that may negatively affect our ability to carry on operations.

We operate in the highly competitive areas of oil and gas exploration, development and production. Factors which affect our ability to successfully compete in the marketplace include, but are not limited to, the following:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment;
- the availability of alternate fuel sources; and
- the intermediate transportation of gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines, and national and local gas gatherers. Many of these competitors possess greater financial and other resources than we do.

The inability to control other associated entities could adversely affect our business.

To the extent that we do not operate all of our properties, our success depends in part upon operations on certain properties in which we may have an interest along with other business entities. Because we have no control over such entities, we are able to neither direct their operations, nor ensure that their operations on our behalf will be completed in a timely and efficient manner. Any delays in such business entities' operations could adversely affect our operations.

There are risks in acquiring producing properties.

We constantly evaluate opportunities to acquire oil and natural gas properties and frequently engage in bidding and negotiating for these acquisitions. If successful in this process, we may alter or increase our capitalization through the issuance of additional debt or equity securities, the sale of production payments or other measures. Any change in capitalization affects our risk profile.

A change in capitalization, however, is not the only way acquisitions affect our risk profile. Acquisitions may alter the nature of our business. This could occur when the character of acquired properties is substantially different from our existing properties in terms of operating or geologic characteristics.

Operating hazards may adversely affect our ability to conduct business.

Our operations are subject to risks inherent in the oil and gas industry, including, but not limited to, the following:

- blowouts;
- cratering;
- explosions;
- uncontrollable flows of oil, gas or well fluids;
- fires;
- pollution; and
- other environmental risks.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Governmental regulations may impose liability for pollution damage or result in the interruption or termination of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

Although we maintain several types of insurance to cover our operations, we may not be able to maintain adequate insurance in the future at rates we consider reasonable, or losses may exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Without limiting the generality of the foregoing, these laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulation could have a significant impact on our operating costs, as well as on the oil and gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, but we do not believe that insurance coverage for environmental damages that occur over time or complete coverage for sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or may lose the privilege to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

You should not place undue reliance on reserve information because reserve information represents estimates.

While estimates of our oil and gas reserves, and future net cash flows attributable to those reserves, were prepared by independent petroleum engineers, there are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control and the control of engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to these reserves, is a function of many factors, including, but not limited to, the following:

- the available data;
- assumptions regarding future oil and gas prices;
- expenditures for future development and exploitation activities; and
- engineering and geological interpretation and judgment.

Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities and oil and gas prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and value of cash flows from those reserves may vary significantly from the estimates. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. For the reserve calculations, oil was converted to gas equivalent at six Mcf of gas for one Bbl of oil. This ratio approximates the energy equivalency of gas to oil on a Btu basis. However, it may not represent the relative prices received from the sale of our oil and gas production.

The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to those reserves included in this document were prepared by independent petroleum engineers in accordance with the rules of the SFAS 69 and the SEC. These estimates are not intended to represent the fair market value of our reserves.

Loss of executive officers or other key employees could adversely affect our business.

Our success is dependent upon the continued services and skills of our current executive management. The loss of services of any of these key personnel could have a negative impact on our business because of such personnel's skills and industry experience and the difficulty of promptly finding qualified replacement personnel.

Our use of hedging arrangements could result in financial losses or reduce our income.

We sometimes engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil and natural gas for a portion of our oil and natural gas production. These hedging arrangements expose us to risk of financial loss in some circumstances, including, without limitation, when:

- production is less than expected;
- the counterparty to the hedging contract defaults on our contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received.

In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and natural gas.

Acquisition of entire businesses may be a component of our growth strategy; our failure to complete future acquisitions successfully could reduce our earnings and slow our growth.

While our business strategy does not currently contemplate the acquisition of entire businesses, it is possible that we might acquire entire businesses in the future. Potential risks involved in the acquisition of such businesses include the inability to continue to identify business entities for acquisition or the inability to make acquisitions on terms that we consider economically acceptable. Furthermore, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions would be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our growth strategy may be hindered if we are not able to obtain financing or regulatory approvals. Our ability to grow through acquisitions and manage growth would require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Risks Related to Our Common Stock

We may need additional capital.

Our board of directors may determine in the future that we need to obtain additional capital through the issuance of additional shares of preferred stock, common stock or other securities. Any such issuance will dilute the ownership interests of the current holders of the Common Stock.

We may issue additional shares of Common Stock.

Pursuant to our certificate of incorporation, our board of directors has the authority to issue additional series of Common Stock and to determine the rights and restrictions of shares of those series without the approval of our stockholders. The rights of the holders of the current series of Common Stock may be junior to the rights of Common Stock that may be issued in the future.

We may issue Preferred Stock with greater rights than our Common Stock.

Although there are no current plans, arrangements, understandings or agreements to issue any preferred stock, our certificate of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from you. Any preferred stock that is issued may rank ahead of our Common Stock for dividend priority and liquidation premiums and may have greater voting rights than our Common Stock.

There may be future dilution of our Common Stock.

To the extent options to purchase Common Stock under employee and director stock option plans are exercised, holders of our Common Stock will be diluted. If available funds and cash generated from our operations are insufficient to satisfy our needs, we may be compelled to sell additional equity or convertible debt securities. The sale of additional equity or convertible debt securities could result in additional dilution to our stockholders.

Our management controls a significant percentage of our outstanding Common Stock and their interests may conflict with those of our stockholders.

Our directors and executive officers and their affiliates beneficially own a substantial percentage of our outstanding Common Stock. This concentration of ownership could have the effect of delaying or preventing a change in control of the Company, or otherwise discouraging a potential acquirer from attempting to obtain control of the Company. This could have a material adverse effect on the market price of the Common Stock or prevent our stockholders from realizing a premium over the then prevailing market prices for their shares of Common Stock.

Sales of substantial amounts of our Common Stock may adversely affect our stock price and make future offerings to raise more capital difficult.

Sales of a large number of shares of our Common Stock in the market or the perception that sales may occur could adversely affect the trading price of our Common Stock. We may issue restricted securities or register additional shares of Common Stock in the future for our use in connection with future acquisitions. Except for volume limitations and certain other regulatory requirements applicable to affiliates, such shares may be freely tradable unless we contractually restrict their resale.

The availability for sale, or sale, of the shares of Common Stock eligible for future sale could adversely affect the market price of our Common Stock.

Provisions in our corporate documents, Delaware law and our shareholders' rights agreement could delay or prevent a change in control of the Company, even if the change would be beneficial to our stockholders.

Certain provisions of our certificate of incorporation and bylaws, as amended, together with our shareholders' rights agreement, may delay, discourage, prevent or render more difficult an attempt to obtain control of the Company, whether through a tender offer, business combination, proxy contest or otherwise. These factors may impair the efforts of a potential buyer of the Company to gain control and discourage transactions that could benefit our shareholders.

We do not expect to pay dividends on our Common Stock.

We do not expect to pay any cash dividends with respect to our Common Stock in the foreseeable future. We intend to retain any earnings for use in our business.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

PHYSICAL PROPERTIES

Our administrative offices are located at 500 North Loop 1604 East, Suite 250, San Antonio, Texas. These offices, consisting of approximately 13,500 square feet, are leased through August 2007 at $0.3 million per year with annual escalations each September 1.

All our oil and gas properties, reserves, and activities are located onshore in the continental United States. There are no quantities of oil or gas subject to long-term supply or similar agreements with foreign government authorities.

PROVED RESERVES, FUTURE NET REVENUE AND PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES

The following unaudited information as of December 31, 2005, relates to our estimated proved oil and gas reserves, estimated future net revenues attributable to those reserves and the present value of the future net revenues using a 10% discount factor ("PV-10 Value"). Our independent reservoir-engineering firms, DeGolyer and MacNaughton, and William Cobb & Associates, both Dallas-based worldwide petroleum-consulting firms, made these estimates for 2005. DeGolyer and MacNaughton also prepared the estimates for 2004. Estimates of proved developed oil and gas reserves attributable to our interest at December 31, 2005, 2004 and 2003 are set forth in Notes to the Audited Consolidated Financial Statements included in this Annual Report on Form 10-K. Netherland, Sewell & Associates, Inc. of Dallas, Texas, prepared our 2003 proved reserves estimates.

The PV-10 Value is based on the estimated future net revenues, as prepared by our independent reservoir engineering firms in accordance with SFAS No. 69. Accordingly, the estimate is net of estimated production, future development costs and future outflows related to asset retirement obligations, and does not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization. PV-10 Value differs from the standardized measure by the present value of estimated income taxes.

Oil prices used in PV-10 Value are based on a December 31, 2005, Koch West Texas Intermediate posted price of $57.75 per barrel, adjusted by lease for quality, transportation fees, regional price differentials and fixed price contracts for the life of each respective contract. Gas prices used in PV-10 Value are based on a December 31, 2005, Houston Ship Channel spot market price of $7.775 per MMBtu, adjusted by lease for energy content, transportation fees, and regional price differentials. Oil and gas prices are held constant. While the methodology is the same across companies, the reference price and adjustments will vary between companies based on conditions in their production areas.

PV-10 Value is considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K. Therefore, we are including the disclosures required by Item 10(e) of Regulation S-K with respect to PV-10 Value. These disclosures include the following reconciliation to the most directly comparable GAAP financial measure ("standardized measure"), and discussion of how management uses the measure and why it is useful to investors.

We believe that the presentation of PV-10 Value is appropriate in our filings and relevant and useful to our investors because:
- it presents the discounted future net cash flows attributable to our proved reserves before corporate future income taxes, and
- it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties.

Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. The PV-10 Value and the standardized measure of discounted future net cash flows are not intended to represent the current market value of the estimated oil and natural gas reserves owned.

Detail of PV-10 and Reconciliation to Standardized Measure

PV-10 Value of Estimated Future Net Revenues, by year, in thousands:	
2006	$28,106
2007	17,805
2008	9,382
2009	9,628
2010	7,128
Thereafter	38,572
Total PV-10 value	110,621
Less present value of estimated income taxes	12,598
Standardized measure	$98,023

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas liquids 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. Proved developed oil and gas reserves are reserves that we can expect to recover through existing wells with existing equipment and operating methods. No reserve estimates have been filed with or included in reports to any federal or foreign government authority or agency, other than the SEC, since our latest Form 10-K filing.

Proved Oil & Gas Reserves at December 31,	2005 Volumes	2005 Mix *	2004 Volumes	2004 Mix *	2003 Volumes	2003 Mix *
Natural gas (Bcf)	9.7	25%	17.7	47%	15.6	55%
Oil (MMBbls)	5.0	75%	3.4	53%	2.1	45%
Natural gas equivalent (Bcfe) *	39.4	100%	37.9	100%	28.4	100%

* Oil and gas were combined by converting oil to gas Mcfe on the basis of 1 barrel of oil = 6 Mcfe of gas.

SALES VOLUMES

The following table summarizes our net oil and gas production, average sales prices, and average production costs per unit of production for the periods indicated.

	Years Ended December 31,		
	2005	2004	2003
Oil:			
Sales volumes in Barrels (Bbl)	397,000	321,000	454,000
Average sales price per Bbl	$54.21	$38.72	$28.30
Gas:			
Sales volumes in Mcf	2,222,000	2,975,000	2,108,000
Average price per Mcf	$7.65	$5.96	$5.48
Mcf equivalent (Mcfe): (1)			
Sales volumes in Mcfe	4,605,000	4,901,000	4,832,000
Average cost per equivalent Mcfe (2)	$1.88	$1.44	$1.22

(1) Oil and gas were combined by converting oil to gas Mcfe on the basis of 1 barrel of oil = 6 Mcfe of gas.
(2) Production costs include direct lease operations and production taxes.

With respect to newly drilled wells, there can be no assurance that current production levels can be sustained. Depending upon reservoir characteristics, such levels of production could decline significantly.

PRODUCING PROPERTIES - WELLS AND ACREAGE

The following table sets forth our producing wells and developed acreage assignable to those wells for the last three fiscal years:

	Developed Acreage		Productive Wells					
			Oil		Gas		Total	
Year Ended	Gross	Net	Gross	Net	Gross	Net	Gross	Net
12/31/05	45,020	26,007	245	204.55	112	65.69	357	270.24
12/31/04	43,850	25,120	291	255.43	201	146.92	492	402.35
12/31/03	35,230	20,423	276	242.74	162	120.49	438	363.23

Productive wells consist of producing wells and wells capable of production, including shut-in wells and wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

A "gross well" or "gross acre" is a well or acre in which we hold a working interest. The number of gross wells or gross acres is the total number of wells or acres in which we own working interests. A "net well" or "net acre" is deemed to exist when the sum of fractional ownership interest in gross wells or gross acres equals one. The number of net wells or net acres is the sum of fractional working interests owned in gross wells or gross acres expressed as whole numbers and fractions thereof.

UNDEVELOPED ACREAGE

As of December 31, 2005, we owned, by lease or in fee, the following undeveloped acres:

United States	Gross Acres	Net Acres	Estimated 2006 Delay Rentals
			($ in thousands)
Texas	758,031	665,104	$ 588
North Dakota	80,124	79,980	157
South Dakota	2,637	1,635	1
Montana	960	960	-
Total	841,752	747,679	$ 746

Seven Texas leases totaling approximately 178,470 gross acres contain varying requirements to drill a well every 90 to 180 days to keep undeveloped portions of the respective leases in effect. We presently drill in accordance with the terms of the leases and expect the leases to remain in force by virtue of production and continuous development during the year.

DRILLING ACTIVITY

The following tables set forth our drilling activity for the last three years:

	2005 (1)		2004		2003	
Completions Summary:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Drilling Well Completions:						
Oil wells (2)	24	17.76	24	21.43	29	26.53
Gas wells (2)	4	2.00	22	11.60	19	11.14
Dry holes	-	-	-	-	1	1.00
Total Drilling Wells Completed	28	19.76	46	33.03	49	38.67
Re-entries Completed:						
Oil wells	1	1.00	3	1.30	8	5.68
Gas wells	2	2.00	3	2.98	0	0.00
Dry holes	-	-	-	-	-	-
Total Re-entries Completed (3)	3	3.00	6	4.28	8	5.68
Wells Completed in Year	31	22.76	52	37.31	57	44.35

(See footnotes at top of next page)

(1) 2005 completions include four each oil and gas well completions later transferred in the Asset Sale.
(2) 2004 column includes one well, each, spudded during December 2003 and completed in 2004.
(3) Total re-entries begun but not completed by year were: 2005 -- 2, 2004 -- 3, 2003 -- 1.

	2005		2004		2003	
In-Progress Recap:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Beginning In-Progress ("BIP")	54	41.86	39	30.37	22	16.23
Add - Wells recategorized to in-progress	3	2.59	-	-	-	-
New re-entries begun not finished	1	0.50	3	1.80	-	-
New wells spud not finished (1)	14	10.11	16	12.19	22	16.14
Less - Completions of BIP	-	-	4	2.50	5	2.0
BIP wells transferred to others	18	14.39	-	-	-	-
Ending In-Progress	54	40.67	54	41.86	39	30.37

(1) New wells spud not finished for 2005 excludes five unfinished wells later transferred in the Asset Sale.

2005 Activity: During 2005, we participated in 52 wells, including new drilling of 47 (32.37 net) wells and the re-entry of five (4.50 net) existing wells. We operated 39 (28.33 net) of the 47 newly drilled wells. Of the current-year drilling wells, 14 (10.11 net) remained in-progress at December 31, 2005. Three of the re-entered wells were put on production in 2005, while the remaining re-entries are pending completion. During 2005, 18 (14.39 net) wells that were in progress at the beginning of the year were transferred to others by sale or exchange agreements. Additionally, we re-entered one beginning in-progress well during 2006 that remains in completion phase.

At December 31, 2005, in-progress wells included 14 development wells spudded in 2005, one new developmental re-entry spudded in 2005, and 39 developmental wells that remain in progress from the beginning of 2005. Most of the in-progress wells are being scheduled for recompletion as horizontal wells or into other zones.

2004 Activity: During 2004, we participated in 69 wells, including new drilling of 60 (43.72 net) wells and the re-entry of nine (6.08 net) existing wells. We operated 48 (38.00 net) of the 69 newly drilled wells. Of the wells drilled in 2004, 16 (12.19 net) remained in progress at December 31, 2004. Six of the re-entered wells were put on production in 2004, while the remaining three re-entries were pending evaluation for recompletion or stimulation. Two of the six re-entries that were producing at year-end 2004 were on wells included as in-progress at the beginning of 2004. Additionally, two wells spudded during 2003 were completed and put on production in early 2004.

At December 31, 2004, in-progress wells included 16 development wells spudded in 2004, three re-entries spudded in 2004, and 35 wells that remained in progress from the beginning of 2004. The 35 remaining prior year in-progress wells included nine CBM wells drilled in 2000 and 2001, whose completion was pending development of the coal field, and 26 other wells being evaluated for recompletion as horizontal wells or into other zones, including 13 in the Glen Rose porosity interval.

2003 Activity: We participated in 80 wells, including new drilling of 71 (54.82 net) wells and the re-entry of nine (6.68 net) existing wells, during 2003. Of the 71 newly drilled wells, we operated 56 (48.25 net) wells. Of the wells drilled in 2003, 22 (16.14 net) remained in progress at December 31, 2003. Eight of the re-entered wells were put on production in 2003, while the remaining well was pending evaluation for recompletion or stimulation.

Year-end 2003 in progress wells included the 22 wells spudded in 2003, one re-entry begun in 2003, and 16 wells that remained in progress from the beginning of 2003. The 16 remaining prior year in-progress development wells included the nine CBM wells previously mentioned, and seven other wells that were being evaluated for recompletion as horizontal wells or into other zones.

Additional information regarding our properties is contained in Item 1 of this Form 10-K and in the Consolidated Financial Statements and Notes thereto under Item 8 of this Form 10-K.

GAS GATHERING SYSTEM

During 2005, we continued to operate our 91-mile pipeline in the Maverick Basin. No significant additions were made in the current year.

During 2004, we entered into an agreement to purchase a 6.1-mile portion of an existing, privately owned pipeline to serve the northwest portion of our lease block at a net price of $200,000. This purchase, and an associated five-year lease on an additional 1.7-mile segment of existing pipeline, expanded our pipeline infrastructure to bring new Burr lease gas production to market. These transactions gave us control of approximately 91 miles of pipeline in the Maverick Basin.

We acquired our gathering system in 2002 to enhance our infrastructure in the Maverick Basin. The initial system included a 69-mile natural gas pipeline, a compressor station with three compressors and three dehydrators that allow the system to have deliverable capacity of 35 MMcfd of which one-third is currently utilized. The pipeline begins approximately 12 miles north of Eagle Pass, Texas, in Maverick County, and runs to Carrizo Springs, Texas, in Dimmit County, where it terminates. The gas can be routed to five separate delivery points and either processed or sold at multiple markets. Also, in 2002, we acquired an additional 10 miles of pipeline from our 62.5%-owned subsidiary, Paloma Pipeline L.P., as well as constructed and placed in service a 3-mile pipeline extension to connect our growing Chittim lease production to the pipeline system.

Our gas gathering system transports our production to various markets. It also transports production for other owners at a set rate per MMbtu. It sells gas at several points along the system with a significant portion being delivered to purchasers through the Enterprise/Gulf Terra Pipeline System or to purchasers behind the Duke Three Rivers processing plant. The gas is processed and the natural gas liquids are removed. The residue gas is then sold to various purchasers. We receive a share of the liquids revenues. Natural gas pricing fluctuations are reflected at the wellhead for our operated gas properties. The following table summarizes our gas marketing sales volumes and average sales prices per MMbtu for the periods indicated. There can be no assurance that current access levels to third party pipelines and processing facilities can be sustained. The following table also reflects the growth in third-party residue gas and natural gas liquids sales:

	Years Ended December 31,		
	2005	2004	2003
Residue gas and NGL sales volumes (MMBtu)	3,082,000	4,062,000	2,935,000
Average sales price per MMBtu	$9.08	$6.69	$5.01

ITEM 3. LEGAL PROCEEDINGS

We are not involved in any matters of litigation.

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

No matter was submitted to a vote of our security holders during the fourth quarter of 2005.

PART II

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

The following is a range of high and low bid prices for our common stock for each quarter presented based upon bid prices reported by the National Association of Securities Dealers Quotations system under the call symbol "TXCO":

	Range of Bid Prices	
Quarter Ended:	**High**	**Low**
December 2005	$ 8.84	$ 5.37
September 2005	7.58	3.90
June 2005	5.98	3.93
March 2005	6.51	4.75
December 2004	$ 6.60	$ 3.98
September 2004	4.61	3.68
June 2004	4.38	3.44
March 2004	7.19	3.89

As of March 3, 2006, there were approximately 1,104 holders of record of our Common Stock. Our transfer agent is the American Stock Transfer & Trust Company, 59 Maiden Lane, New York, New York 10038. We have not paid any cash dividends on our Common Stock in past years and do not expect to do so in the foreseeable future. Our credit facility prohibits the payment of dividends to common shareholders.

The following table reflects balances on our equity compensation plans at December 31, 2005:

Plan category *(securities in thousands)*	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)**	**Weighted-average exercise price of outstanding options, warrants and rights (b)**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)**
Equity compensation plans approved by security holders	1,254	$2.86	982
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	1,254	$2.86	982

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial information is derived from and qualified in its entirety by our Audited Consolidated Financial Statements and the Notes thereto as set forth in this Annual Report on Form 10-K commencing on page F-1.

	Years Ended December 31				
(In thousands, except earnings per share data)	2005	2004	2003	2002	2001
Operating revenues	$ 67,000	$ 57,735	$ 39,545	$ 18,958	$ 13,759
Net income (loss)	13,741	2,797	41	(311)	(50)
Earnings (loss) per common share:					
Basic	0.48	0.11	0.00	(0.02)	(0.00)
Diluted	0.48	0.10	0.00	(0.02)	(0.00)
Net cash provided by operating activities	6,260	16,447	15,158	7,389	8,564
Net cash provided (used) by investing activities	25,525	(39,718)	(36,282)	(27,655)	(11,895)
Net cash provided (used) by financing activities	(28,820)	20,208	24,971	20,580	(548)
Total assets	109,536	114,237	84,206	53,036	29,843
Long-term obligations	2,289	31,654	28,909	7,217	862
Stockholders' equity	$ 83,281	$ 65,682	$ 42,792	$ 36,970	$ 23,057
Weighted average shares outstanding:					
Basic	28,444	26,066	20,781	19,081	17,441
Diluted	28,885	26,971	21,295	19,081	17,441

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

OVERVIEW

The following is a discussion of our financial condition and results of operations. This discussion should be read in conjunction with our Financial Statements and Notes thereto, which begin on page F-1 of this Annual Report of Form 10-K.

We are an independent oil and gas enterprise with interests primarily in the Maverick Basin in Southwest Texas, and the Marfa Basin of West Texas, with a consistent record of long-term growth in proved oil and gas reserves, leasehold acreage position, production and cash flow through our established exploration and development programs. Our business strategy is to build shareholder value by acquiring undeveloped mineral interests and internally developing a multi-year drilling inventory through the use of advanced technologies, such as 3-D seismic and horizontal drilling. We account for our oil and gas operations under the successful efforts method of accounting and trade our common stock on the Nasdaq Capital Market[SM] under the symbol "TXCO."

We currently have three drilling rigs under operation on our extensive 656,000-acre position in the Maverick Basin. We expect to begin exploration activities in the Marfa Basin in the third quarter of 2006. Completions in 2005 included 25 oil and six gas wells, which included three re-entries, while 16 wells spud during the year remained in progress at year-end. Eight of the 2005 completions were later transferred in the Asset Sale. Current emphasis is on the Glen Rose, Georgetown and San Miguel formations. The 2006 capital expenditures budget includes funds for 57 wells (28 in the Glen Rose, 10 in the Georgetown, 11 in the San Miguel, eight in the Pearsall), as well as funds for seismic and lease acquisitions.

Due to the number of promising prospects on our Maverick Basin acreage, as well as higher oil and gas prices, drilling activity remained high during 2005. (For further discussion of this activity, see the "Principal Areas of Activity" and "Drilling Activity" sections of this Form 10-K). The increased expenditures should translate into continued increases to reserves as adequate production history is established. Revenues and credit capacity for future activity should continue to grow as the result of the increased drilling activity. Recognition of additional reserves for newly drilled wells requires a period of sustained production, causing a delay between the expenditures and the recording of reserves.

We reported net income of $13.7 million, or $0.48 per basic and diluted share, for the year ended December 31, 2005, compared to net income of $2.8 million, or $0.11 per basic share and $0.10 per diluted share, for the prior year. The primary contributor to this improvement was the $24.5 million pre-tax gain on the sale of selected interests in the Maverick Basin to EnCana Oil & Gas (USA) Inc. Higher average sales prices also contributed to the improvement, partially offset by decreased margin on gas gathering activities, slightly lower production on an equivalent unit basis, and increases in lease operating expenses, depreciation and depletion. These factors are discussed in the Results of Operations section.

We continued our ongoing trend of annual reserve growth in 2005 by recording net proved reserve additions of 1.5 Bcfe. Combined with annual production of 4.6 Bcfe and reserves sold of 1.4 Bcfe, our gross reserve additions for the year were 7.5 Bcfe. Estimated year-end proved oil and gas reserves were a record 39.4 Bcfe, 4.0% above the 37.9 at year-end 2004. We achieved a 161% all-source reserve replacement rate in 2005. Positive cash flow provided from operations totaled $6.3 million, a 61.9% decrease from the prior year primarily due to losses on the termination of hedges of natural gas and increased income taxes after the Asset Sale. The following table illustrates key features of our continuous development over the four fiscal years presented.

	Year Ended December 31,			
Development:	**2005**	**2004**	**2003**	**2002**
No. of oil wells completed ***(1)***	25	27	37	14
No. of gas wells completed ***(1)***	6	25	19	16
No. of oil wells purchased	-	-	-	94
Gas sales (MMcf)	2,222	2,975	2,108	2,487
Gas reserve additions from drilling (MMcf)	5	6,432	5,037	5,103
Oil sales (MBbl)	397	321	454	314
Oil reserves additions from drilling (MBbl)	522	1,396	1,115	600
Gas equivalent sales (Bcfe)	4.6	4.9	4.8	4.4
Reserve additions (Bcfe)				
Drilling	3.2	14.8	11.7	8.7
Revisions of previous estimates	4.3	(0.9)	(2.7)	2.5
Purchased in place	-	0.5	0.7	4.0
Total reserves added (Bcfe) ***(2)***	7.5	14.4	9.7	15.2
Reserve replacement rate ***(3)***				
Drill bit	161%	283%	186%	255%
Drill bit plus purchases (all sources)	161%	295%	200%	347%
Non-developed Texas acreage leased	758,031	491,289	479,761	408,992
Non-developed Williston Basin acreage leased	83,721	84,654	91,804	91,804

(1) Includes four gas and four oil wells completed in 2005 that were later transferred in the Asset Sale.
(2) Make-up of total proved developed reserves at year-end 2005: 42% gas, 58% oil.
(3) The reserve replacement ratio is calculated by dividing proved reserve additions, which includes extensions and discoveries, revisions to previous estimates and reserves purchased, as the numerator, by the sales volumes for the year as the denominator. For the drill bit only ratio, any purchased reserves are excluded from the numerator. See discussion regarding risk factors included in Part I, Item 1A of this Form 10-K. See the discussion below regarding how management uses this information and potential time horizons for realization of these reserves.

2005 Asset Sale: In 2005, we entered into a purchase and sale agreement with EnCana Oil & Gas (USA) Inc. ("EnCana") to sell selected interests in our Maverick Basin interest effective September 1, 2005, for $80 million. EnCana acquired interests in approximately 300,000 gross acres across the southern portion of our Maverick Basin acreage, excluding the Glen Rose formation under the entire block and the San Miguel formation in the Pena Creek field. EnCana also received 50% of our interest in approximately 220,000 gross acres across the northern portion of our Maverick Basin acreage below the Glen Rose formation, including the Pearsall and Jurassic formations.

Approximately 3% of our estimated proved reserves at June 30, 2005, and 19% of our existing production at September 1, 2005, were transferred in this sale. At closing, our future working interest (WI) in the oil and gas rights attributable to the Glen Rose formation increased to 100% across the acreage block acquired in the asset exchange with Arrow River Energy LP and CMR Energy LP in February 2005, and to 75.5% on the Comanche Ranch leaseblock. We retained our 100% WI in the San Miguel formation on Pena Creek field, as well as our extensive gas gathering and transmission pipeline assets. A pre-tax gain of $24.5 million was recognized on this transaction in the third quarter. Proceeds from the transaction were used to redeem the Preferred Stock for $16 million and pay down $32 million on the Credit Facility effective September 30, 2005. Additionally, funds were used to terminate derivative contracts on natural gas for November 2005 through April 2007, requiring a cash payment of approximately $9.9 million that substantially offset the accrued derivative obligations recorded in the first three quarters of 2005. Funds were also used to acquire leasehold interests in the Marfa Basin of West Texas.

Subsequent Acquisition: On March 10, 2006, we closed on the purchase of a drilling rig and other personal property and equipment from Ada Energy Services, LLC. The consideration for the purchase was $4.3 million.

Reserve Replacement

Historically, we add proved reserves through both drilling and acquisition activities. We believe we will continue to add reserves each year, however, external factors beyond our control, such as governmental regulations and commodity market factors, could limit our ability to drill wells and acquire proved properties in the future. We calculate and analyze reserve replacement ratios to use as benchmarks against our competitors. Oil and gas companies are judged by their management and the investing public by their effectiveness in replacing annual production, hence the need for these ratios. The ratios are limited in use by the inherent uncertainties in the reserve estimation process and other factors. Our reserve additions for each year are estimates. Reserve volumes can change over time, and therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact the ability to access these reserves, such as availability of capital, new and existing government regulations, competition within the industry, the requirement of new or upgraded infrastructure at the production site, and technological advances. See "Risk Factors" (Part I, Item 1A) for further discussion of risks and uncertainties related to reserves.

The reserve report prepared by independent reservoir engineers and used for both the PV-10 Value and the standardized measure, indicates the last year of production is estimated as 2080. However, as shown in the table in Item 2 of this Form 10-K, we expect to realize approximately 65.1% of that production by year-end 2010.

CAPITAL RESOURCES AND LIQUIDITY

Liquidity is a measure of ability to access cash. Our primary needs for cash are for exploration, development and acquisitions of oil and gas properties, repayment of contractual obligations and working capital funding. We have historically addressed our long-term liquidity requirements through cash provided by operating activities, the issuance of debt and equity securities when market conditions permit, sale of non-strategic assets, and more recently through the Credit Facility. The prices for future oil and natural gas production and the level of production have significant impacts on operating cash flows and cannot be predicted with any degree of certainty. We continue to examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of common stock, the sales of non-strategic assets, and joint venture financing. Availability of these sources of capital and, therefore, our ability to execute our operating strategy will depend upon a number of factors, some of which are beyond our control. We believe that projected operating cash flows, cash on hand, and borrowings under the Credit Facility, will be sufficient to meet the requirements of our business. However, future cash flows are subject to a number of variables including the level of production and oil and natural gas prices. No assurances can be made that operations and other capital resources will provide cash in sufficient amounts to maintain our planned levels of capital expenditures or that we will not increase capital expenditures. Actual levels of capital expenditures may vary significantly due to a variety of factors, including but not limited to drilling results, product pricing and future acquisition and divestitures of properties.

Bank Credit Facility

We have a $50 million senior secured revolving credit facility with Guaranty Bank (the "Facility" or "credit facility"). The Facility was entered into in 2004 and expires in June 2008. It replaced our prior $25 million credit facility with Hibernia National Bank, which was scheduled to mature in 2006.

The credit facility is collateralized by all of our proven oil and gas properties, had an initial borrowing base of $12.3 million, based on then current levels of our oil and gas reserves, and features semi-annual redeterminations. The borrowing base was subsequently increased based on reserves, and amendments were made during 2005 that modified the covenant terms and extended the termination date through June 2008. At December 31, 2005, the borrowing base, inclusive of traunche A and traunche B, stood at $29.0 million. The unused borrowing base at March 3, 2006, was $24.4 million, with $4.6 million outstanding at an average interest rate of 6.78%. Interest under the Facility is based on, at our option, (a) the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 2.00% to 2.50% or (b) prime plus an applicable margin ranging from 0.00% to 0.25%. The Facility provides the lender a commitment fee equal to 0.5%, per annum on the unused borrowing base.

The Facility contains additional terms and conditions consistent with similarly positioned companies. These conditions include various restrictive covenants such as minimum levels of interest coverage, tangible net worth and current ratio, a maximum debt to EBITDAX ratio, restricting the payment of dividends other than the dividends payable under the redeemable preferred stock, and prohibiting a change of control or incurring additional debt. The Facility's requirement for hedging a percentage of production, when borrowing under the Facility exceeded 50% of the borrowing base was removed during 2005. At December 31, 2005, we were in compliance with all covenants.

2006 Capital Requirements Outlook

Overall: We believe the Facility, along with our positive cash flow from existing production and anticipated production increases from new drilling, will provide adequate capital to fund operating cash requirements and complete our scheduled exploration and development goals for 2006. We expect to further increase our borrowing base commensurate with the expected growth of our proved oil and gas reserves throughout the base term of the Facility. Should product prices weaken, or expected new oil and gas production levels not be attained, the resulting reduction in projected revenues would cause us to re-evaluate our working capital options and would adversely affect our ability to carry out our current operating plans.

The major components of our plans, and the requirements for additional capital for 2006, include the following:

Maverick Basin Activity**:** Initial capital expenditures for 2006 are planned to be in the range of $40 million to $50 million and target our Maverick Basin core properties, primarily for drilling wells. $2.1 million is earmarked for seismic and leasehold enhancements and other infrastructure expansion activities. Our budgeted capital expenditures are intended to be flexible. The budget may expand or contract based on drilling results, operational developments, drilling rig availability, unanticipated transaction opportunities, market conditions, commodity price fluctuations and working capital availability.

We plan to drill or re-enter 57 wells, including 28 Glen Rose wells (including 24 porosity zone oil wells), 10 Georgetown wells, 11 San Miguel oil wells and eight Pearsall wells. The porosity wells include 20 new wells and four re-entries. Other companies will operate some of these wells and, therefore, we do not have direct control over when they will be drilled or what final costs will actually be incurred. The following table details typical gross well costs budgeted for 2006 wells:

	Typical Gross Well Costs	
(In thousands)	**Dry Hole**	**Completed**
Glen Rose oil porosity zone horizontal well	$1,000	$1,200
Glen Rose shoal horizontal gas well	1,000	1,300
Glen Rose vertical well	450	600
Georgetown horizontal oil well	600	750
Pearsall/Sligo gas well	1,000	2,000
San Miguel waterflood oil well	180	330
San Miguel tar sand oil well	150	250

Marfa Basin Activity: We made our first investment in this basin during the fourth quarter of 2005. The basin is geologically similar to the gas-prone Fort Worth and Arkoma Basins and is highly prospective for gas production from the Barnett and Woodford Shales. We are seeking a 50% partner and expect to begin exploration activities in the third quarter of 2006. No funds were included in the initial 2006 CAPEX budget for this area. However, we expect to increase the CAPEX budget to include one or two wells once our partner is determined.

Williston Basin Activity: We plan to maintain our existing producing properties and the payment of delay rentals and lease extensions on selected undeveloped leases, with scheduled 2006 delay rentals of $157,000. We will continue to offer remaining acreage, seismic data, and identified prospects to other industry operators. We participated in the drilling of one well in the Williston Basin during 2005 and anticipate additional activity during 2006. No funds are included in our 2006 CAPEX budget for this area.

Sources and Uses of Cash for the Year Ended December 31, 2005

Net cash provided by operating activities was $6.3 million for 2005, down 61.9% from $16.4 million for 2004. The decline is largely due to a one-time cash outlay in excess of $9.9 million for the termination of derivative contracts. This is coupled with increased federal and state income taxes resulting from the Asset Sale of $3.9 million. The following table illustrates the impact of the items to cash provided by operations and how, on an adjusted basis, the respective periods compare.

	2005	2004	2003
Net cash provided by operating activities	$6,260	$16,447	$15,158
Adjustments:			
Payment to terminate derivative treated as an investment	7,564	-	-
Payment to terminate cash flow hedge	2,356		
Federal income tax	3,923	146	50
Adjusted cash provided by operating activities	$20,103	$16,593	$15,208

Total cash available from all sources, listed in the following table, provided $108.4 million for use in the ongoing expansion, development and exploration of our oil and gas properties. This represents a 78.5% increase over the $60.7 million total cash available for 2004. Included in cash from other sources for 2005 were proceeds from the sale of selected interests to EnCana, described in the Overview section, and from the exercise of warrants and options to purchase common stock. Proceeds were used to expand our capital expenditure program, pay off essentially all long-term debt, enhance balance sheet liquidity, complement on-going operations and provide for general corporate purposes.

2005 Cash Available
(In thousands)

Beginning cash reserves, January 1, 2005		$ 3,118
Net cash provided by operating activities		6,260
Internally generated funds		9,378
Proceeds from sale of assets	$ 78,002	
Issuance of common stock, net of expenses	5,683	
Proceeds from bank credit facility	15,001	
Proceeds from installment obligations	356	
Total other sources of cash		99,042
2005 Cash Available		$ 108,420

We applied $52.5 million to fund the expansion and ongoing development of our oil and gas properties, a $12.8 million or 32.1% increase from 2004. Included were drilling, completions, seismic and leasehold acquisition costs primarily targeting our core area, the Maverick Basin. This represented expenditures for the drilling, completion and re-entry of 52 oil and gas wells and new Marfa Basin mineral lease purchases totaling approximately 140,000 gross acres. Also included were expenditures for 3-D seismic on an additional 140 square miles of our Maverick basin lease block and other equipment used in the field.

2005 Uses of Cash
(In thousands)

Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 52,440
Other property and equipment	37
Sub-total	52,477
Debt principal payments	33,860
Redemption of preferred stock	16,000
2005 Cash Utilized	$ 102,337

We made timely payments of $33.9 million on our long-term debt obligations and redeemed all of our preferred stock for $16 million during 2005, while payments of interest totaled $3.2 million.

As a result of these activities, we ended 2005 with a current ratio of 0.70 to 1 and a negative working capital of $7.2 million, compared with 0.70 to 1 and negative $5.5 million, respectively, at December 31, 2004.

2005 Acquisitions: In October 2005, we acquired a 100% working interest in 140,000 gross acres in the Marfa Basin. We paid for this acquisition with 450,000 shares of unregistered stock and an undisclosed amount of cash. The basin is located in west Texas, along the Ouachita Thrust, and is prospective for natural gas from the Barnett and Woodford shales.

In February 2005, we acquired a 50% interest in more than 174,000 gross acres that were mostly continquous with our existing Maverick Basin acreage block. We exchanged a 50% interest in shallow zones in certain of our Comanche and Chittim leases, and all depths in certain other Chittim leases, for the interest.

Sources and Uses of Cash for the Year Ended December 31, 2004

Net cash provided by operating activities was $16.4 million for 2004, up 8.5% from $15.2 million for 2003. Total cash available from all sources, listed in the following table, provided $60.7 million for use in the ongoing expansion, development and exploration of our oil and gas properties. This represents a 24.2% increase over the $48.9 million total cash available for 2003. Cash from other sources for 2004 included funds raised from private placements of common stock, as well as proceeds from the exercise of warrants and options to purchase common stock. Proceeds were used to expand our capital expenditure program, enhance balance sheet liquidity, complement on-going operations and provide for general corporate purposes. Pursuant to the private placement agreement, we filed a Form S-3 Registration Statement dated June 18, 2004, covering the issued shares on behalf of the investors.

2004 Cash Available
(In thousands)

Beginning cash reserves, January 1, 2004		$ 6,181
Net cash provided by operating activities		16,447
Internally generated funds		22,628
Issuance of common stock, net of expenses	$ 18,620	
Borrowings on the bank credit facility	19,099	
Proceeds from installment obligations	377	
Total other sources of cash		38,096
2004 Cash Available		$ 60,724

We applied $39.7 million to fund the expansion and ongoing development of our oil and gas properties, a $3.2 million or 8.9% increase from 2003. Included were drilling, completions, seismic and leasehold acquisition costs primarily in the Maverick Basin. This represented expenditures for the drilling, completion and re-entry of 69 oil and gas wells and new Maverick Basin mineral lease and seismic option purchases totaling approximately 74,000 acres; as well as acquisition and lease of 7.8 miles of natural gas pipeline. Also included were expenditures for 3-D seismic on an additional 44 square miles of our Maverick basin lease block and other equipment used in the field.

2004 Uses of Cash
(In thousands)

Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 39,335
Other property and equipment	224
Net distributions to minority interests	159
Sub-total	39,718
Debt principal payments	17,888
2004 Cash Utilized	$ 57,606

We made timely payments of $17.9 million on our long-term debt obligations during 2004, including $16.0 million paid on the original credit facility and later re-borrowed on our new Facility, while payments of interest totaled $3.0 million.

As a result of these activities, we ended 2004 with a current ratio of 0.70 to 1 and a negative working capital of $5.5 million, compared with 0.83 to 1 and negative $2.3 million, respectively, at December 31, 2003.

2004 Acquisitions: We acquired interests in several properties during 2004 in exchange for cash and/or shares of common stock. The Hollimon lease acquisition signed in March, and later amended, gives us a 75% interest in 12,200 acres and included a 3-D seismic survey of the area. In June, we acquired a 75% WI in seismic option agreements on approximately 62, 000 gross acres adjacent to our Burr and Wipff leases. In October, we entered into agreements to purchase a 6.1-mile portion of an existing, privately owned pipeline to serve the northwest portion of our lease block and, in a related transaction, signed a five-year lease on an additional 1.7-mile segment of existing pipeline.

Sources and Uses of Cash for the Year Ended December 31, 2003

Net cash provided by operating activities was $15.2 million for 2003, up 105% or $7.8 million, from $7.4 million for 2002. Total cash available from all sources, listed in the following table, provided $48.9 million for use in the ongoing expansion, development and exploration of our oil and gas properties. This represents a 56.3% increase over the $31.3 million total cash available for 2002. Included in cash from other sources for 2003 were funds raised from a private placement of mandatorily redeemable preferred stock and common stock, see Note E to the Audited Consolidated Financial Statements, which were used to fund the expanded drilling program for 2003 and pay-down the credit facility.

2003 Cash Available
(In thousands)

Beginning cash reserves, January 1, 2003		$ 2,334
Net cash provided by operating activities		15,158
Internally generated funds		17,492
Private placement of 2,133,333 shares of common stock and 16,000 shares of redeemable preferred stock, net of expenses	$15,011	
Borrowings on the bank credit facility	13,200	
Borrowings on installment obligations	2,990	
Net distributions to minority interests	186	
Total other sources of cash		31,387
2003 Cash Available		$ 48,879

We applied $36.5 million to fund the expansion and ongoing development of our oil and gas properties, a $9 million or 33% increase from 2002. Included were drilling, completions, seismic and leasehold acquisition costs primarily targeting our core area. This represented expenditures for the drilling, completion and re-entry of 80 oil and gas wells and new Maverick Basin mineral lease purchases of approximately 71,000 acres. Also included were expenditures for 3-D seismic on 37 square miles of our Burr lease block and other equipment used in the field.

2003 Uses of Cash
(In thousands)

Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 36,071
Other property and equipment	397
Sub-total	36,468
Debt principal payments	6,230
2003 Cash Utilized	$ 42,698

We made timely payments of $6.2 million on our long-term debt obligations during 2003, including $5.0 million paid and later re-borrowed on the Credit Facility, while payments of interest totaled $1.2 million.

As a result of these activities, we ended 2003 with a current ratio of 0.83 to 1 and a negative working capital of $2.3 million, compared with 0.81 to 1 and negative $1.9 million, respectively, at December 31, 2002.

Burr Ranch Acquisition: In January 2003, we acquired the 70,700-acre Burr Ranch lease. The acreage is contiguous to our existing acreage block. We entered into an unsecured installment obligation with the mineral owner in connection with this acquisition. Imputed interest due on the obligation is 4.25% per annum. Subsequent to year-end 2003, installments of $1.4 million were made in January of 2004 and 2005.

RESULTS OF OPERATIONS

The following table highlights the percentage change from the preceding year for selected items that are significant in our industry. For full information see the Consolidated Statements of Operations and the Sales Volumes discussion.

Change in Selected Income Statement Items:	**2005 vs. 2004**	**2004 vs. 2003**	**2003 vs. 2002**
Operating revenues	+ 16.0%	+ 46.0%	+ 108.6%
Gas gathering revenues	+ 3.2	+ 81.8	+ 483.2
Gas gathering expenses	+ 11.9	+ 67.1	+ 476.6
Lease operations expense	+ 18.5	+ 23.9	+ 8.0
Impairment & abandonments	- 40.3	- 6.7	+ 102.4
Depreciation, depletion & amortization	+ 27.9	+ 14.2	+ 32.7
Net income (loss)	+ 391.3	+ 6,742.1	+ 113.1
Basic income (loss) per common share	+ 336.4	+ 100.0	+ 112.5

Change in Selected Operating Items:	**2005 vs. 2004**	**2004 vs. 2003**	**2003 vs. 2002**
Oil sales volumes (Bbl)	+ 23.6%	- 29.2%	+ 44.4%
Gas sales volumes (Mcf)	- 25.3	+ 41.1	- 15.2
Combined sales volumes (Mcfe)	- 6.1	+ 1.5	+ 10.5
Net residue and NGL sales volumes (MMbtu)	- 24.1	+ 38.8	+ 21.4
Oil average sales price per Bbl	+ 40.0	+ 36.8	+ 15.2
Gas average sales price per Mcf	+ 28.3	+ 8.9	+ 63.5
Residue & NGL sales price per MMbtu	+ 35.7	+ 33.5	+ 36.1

The following table provides further detail on the growth of our gas gathering operations:

Gas Gathering Results: ***($ in thousands)***	**2005**	**2004**	**2003**
Revenues:			
Residue gas sales	$23,330	$20,967	$11,801
Natural gas liquids sales	4,652	6,205	2,908
Transportation and other revenue	448	364	436
Total gas gathering revenues	28,430	27,536	15,145
Expense:			
Third-party gas purchases	27,112	23,937	14,019
Transportation and marketing expenses	278	498	369
Direct operating costs	922	857	748
Total gas gathering operations expense	28,312	25,292	15,136
Gross margin	$ 118	$ 2,244	$ 9

2005 Compared to 2004

We reported a net income of $13.7 million, $0.48 per basic and diluted share, for the year ended December 31, 2005, compared to a net income of $2.8 million, $0.11 per basic share and $0.10 per diluted share for the prior year.

Total revenues for 2005 increased by $9.3 million compared to 2004. Natural gas sales volumes decreased by 753 MMcf while oil sales volumes increased by 75,911 barrels of oil (BO), 455 MMcfe, as compared with the prior year. Gas gathering revenues increased by $0.9 million over 2004 levels.

The decrease in natural gas sales volumes was primarily due to the sale of interests in certain Georgetown wells as part of the EnCana sale, as well as normal declines experienced in maturing gas wells. The increase in 2005 oil sales volumes compared to the prior year reflects the increase in our interests on most Glen Rose wells drilled following the EnCana transaction, as well as the resumption of drilling in the Glen Rose porosity play after delays in the prior year due to a partner's restructuring. On an equivalent-unit basis, prices averaged 35.9% higher in 2005 as compared to 2004. Crude oil prices averaged 40.0% higher while natural gas prices were up 28.3%. Average higher prices for 2005, as compared to 2004, had a $9.9 million positive impact on revenues in 2005. Commodity prices have been, and continue to be, volatile. During 2005, realized gas prices ranged from a high of $12.66 per Mcf in October to a low of $5.75 per Mcf in January, while realized crude oil prices ranged from a high of $62.87 in August to a low of $43.13 in January. During 2004, realized gas prices ranged from a high of $8.05 per Mcf in November to a low of $4.52 per Mcf in September, while realized crude oil prices ranged from a high of $49.49 in October to a low of $31.06 in February. Average daily net gas sales in 2005 were 6.1 MMcf, a 25.0% decrease from the prior year, as the result of producing wells sold and normal production declines on maturing wells. Average daily net oil production rates in 2005 were 1,088 Bbls, a 24.0% increase from the prior year, primarily as a result of our increased working interest in new Glen Rose formation wells.

Lease operating expense for 2005 increased $1.0 million, from $5.5 million in 2004 to $6.5 million in 2005, an 18.5% increase. This increase is primarily due to the addition of 24 new oil wells during 2005. The increase reflects the incremental direct costs of operating the new wells, including the usual costs such as pumper, electricity, water disposal, and other direct overhead charges. Operating expense per Mcfe increased $0.44 from $1.44 in 2004 to $1.88 in 2005. Typically, waterfloods incur higher costs of operations. Excluding the Pena Creek field, operating expense per Mcfe for 2005 is $1.57, an increase of $0.35 from the prior year. Also, included in operating costs is the cost of operating the CBM wells. These costs totaled $221,000 in 2005 and $478,000 in 2004. The CBM wells are in the dewatering phase and therefore have little production relative to their operating costs. Operating cost per Mcfe excluding the CBM wells and Pena Creek averaged $1.52 in 2005 and $1.12 in 2004. We sold a 50% interest in most of our CBM properties in February 2005 and the remaining 50% of the same properties in September 2005.

Pursuant to the successful efforts method of accounting for mineral properties, we periodically assess our producing and non-producing properties for impairment. Impairment and abandonments decreased by 40.3% primarily due to higher expected cash flows. Depreciation, depletion and amortization increased by $2.7 million, or 27.9%, over 2004 consistent with the number of newly drilled producing wells being depleted. The increase in depreciation was due to increased investments in other equipment including computer, pipeline and well service equipment additions. The increase in amortization primarily reflects the acquisition of 3-D seismic and additional loan fees.

Gas gathering operations revenues increased 3.2% in 2005 as compared to 2004. Related operating expenses increased 11.9% from 2004. These increases are consistent with the increased number of gas wells connected to the gathering system compared to the prior period, as well as higher average commodity prices. See the table on the previous page.

While general and administrative costs increased 12.1% when compared to 2004 levels, they declined to 8.1% of revenues. This compares favorably to 2004 when general and administrative expenses were 8.4% of revenues. The higher level of absolute-dollar costs reflects our higher sustained level of operations. The increase also reflects higher salaries, benefits, and office-related expenses for a full year related to three employees hired across the organization during 2004, along with a partial year for two new employees hired during 2005. Also contributing to the increase were higher costs for Sarbanes-Oxley compliance and franchise taxes. The prior year also included a $237,000 non-cash compensation charge relating to one-year extensions of the expiration date for a non-qualified option and warrant. Increases in 2005 general and administrative costs are consistent with the expanded compliance burden mandated by the adoption of the Sarbanes-Oxley Act in mid-2002, see "Sarbanes-Oxley Section 404 Implementation" for additional discussion. These particular costs are likely to continue to increase as the compliance burden expands.

The 178.1% increase in interest income reflects higher average cash levels in interest-bearing accounts, primarily after the Asset Sale. Interest expense was essentially flat in 2005 as compared to 2004 due to higher average debt levels in the first nine months of the year, prior to the Asset Sale. Proceeds from that sale essentially eliminated our debt. The derivative mark-to-market loss of $2.1 million represents the $2.0 million unrealized fair value loss at year-end on oil hedges and the reversal of a $0.1 million unrealized fair value gain at December 31, 2004, while the $9.1 million derivative settlements loss reflects the termination of gas hedges during October 2005 and cash settlements for closed periods. Both are for hedges accounted for as investments.

2004 Compared to 2003

We reported a net income of $2.8 million, $0.11 per basic share and $0.10 per diluted share, for the year ended December 31, 2004, compared to a net income of $0.04 million or $0.00 per basic and diluted share for the prior year.

Total revenues for 2004 increased by $18.2 million compared to 2003. Natural gas sales volumes increased by 866.6 MMcf while oil sales volumes declined by 132,675 BO as compared with the prior year. Gas gathering revenues increased by $12.4 million over 2003 levels.

The increase in natural gas sales volumes was primarily due to Pena Creek, Georgetown and Chittim Glen Rose horizontal wells placed on production in 2004. The decline in 2004 oil sales volumes compared to the prior year reflects the delay in drilling in the Glen Rose porosity play due to a partner's restructuring. On an equivalent-unit basis, prices averaged 22.0% higher in 2004 as compared to 2003. Crude oil prices averaged 36.8% higher while natural gas prices were up 8.9%. Average higher prices for 2004, as compared to 2003, had a $4.8 million positive impact on revenues in 2004. Commodity prices have been, and continue to be, volatile. During 2004, realized gas prices ranged from a high of $8.05 per Mcf in November to a low of $4.52 per Mcf in September, while realized crude oil prices ranged from a high of $49.49 in October to a low of $31.06 in February. During 2003, realized natural gas prices ranged from a high of $7.26 per Mcf in March to a low of $4.85 per Mcf in November, with realized crude oil prices ranging from a high of $34.32 in February to a low of $25.63 in May. Average daily net gas sales rates in 2004 increased to 8.1 MMcf, a 40.7% increase from the prior year, as production from new wells greatly exceeded the normal decline in aging gas well production. Average daily net oil sales rates in 2004 decreased to 878 Bbls, a 29.4% decline from the prior year, primarily as a result of the delay in drilling mentioned above.

Lease operating expense for 2004 increased $1.1 million, from $4.4 million in 2003 to $5.5 million in 2004, a 23.9% increase. This increase is primarily due to the addition of 27 new oil wells and 25 new natural gas wells during 2004. The increase reflects the incremental direct costs of operating the new wells, including the usual costs such as pumper, electricity, water disposal, and other direct overhead charges. Operating expense per Mcfe increased $0.22 from $1.22 in 2003 to $1.44 in 2004. Typically, waterfloods incur higher costs of operations. Excluding the Pena Creek field, operating expense per Mcfe for 2004 is $1.22, an increase of $0.11 from the prior year. Also, included in operating costs is the cost of operating the CBM wells. These costs totaled approximately $0.5 million in both 2004 and 2003. The CBM wells were in the dewatering phase and therefore had little production relative to their operating costs. Operating cost per Mcfe excluding the CBM wells and Pena Creek averaged $1.12 in 2004 and $1.01 in 2003.

Pursuant to the successful efforts method of accounting for mineral properties, we periodically assess our producing and non-producing properties for impairment. Impairment and abandonments decreased by 6.7% primarily due to lower impairment rates. Depreciation, depletion and amortization increased by $1.2 million, or 14.2%, over 2003 due primarily to the increased number of producing wells being depleted for wells added through the drill bit. The increase in depreciation was due to increased investments in other equipment including computer, pipeline and well service equipment additions. The increase in amortization was primarily due to the acquisition of 3-D seismic and additional loan fees.

Gas gathering operations revenues increased 81.8% in 2004 as compared to 2003. Related operating expenses increased 67.1% from 2003. These increases were consistent with the increased number of gas wells connected to the gathering system compared to the prior period, as well as higher average sales prices.

While general and administrative costs increased 30.6% when compared to 2003 levels, they represented only 8.4% of revenues. This compares favorably to 2003 when general and administrative expenses were 9.4% of revenues. The higher level of absolute dollar costs reflects our higher sustained level of operations. The increase also reflects higher salaries, benefits, and office-related expenses for a full year related to 10 employees hired across the organization during 2003, along with a partial year for three new employees hired during 2004. Additionally 2004 includes a $0.2 million non-cash compensation charge relating to one-year extensions of expiration dates for a non-qualified option and warrant. Also contributing to the increase were higher costs for public company and investor relations related expenses, and professional services. Increases in 2004 general and administrative costs are consistent with the expanded compliance burden mandated by the adoption of the Sarbanes-Oxley Act in mid-2002, see "Sarbanes-Oxley Section 404 Implementation" for additional discussion. These particular costs are likely to continue to increase as the compliance burden expands.

The 19.3% increase in interest income reflects slightly higher average cash levels in interest-bearing accounts. Interest expense increased by $1.6 million in 2004 from 2003 due to higher average debt levels, reflecting a full year of interest on the redeemable preferred stock issued in August 2003 and slightly higher average interest rates on the Credit Facility. A portion of the interest expense is a non-cash accrual reflecting the accretion of the liability on the preferred stock to its full redemption value, which is classified as a long-term liability on the balance sheet. The derivative fair value loss of $19,000 represents the net of the unrealized fair value gain at December 31, 2004 of $0.1 million and the $0.2 million in cash settlements for closed periods.

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES AND COMMITMENTS

The following is a summary of our future payments on obligations as of December 31, 2005.

	Payments Due by Period				
Contractual Obligations	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**	**Total**
Long-term debt	$ 262	$ 1	$ -	$ -	$ 263
Operating lease obligations	341	251	44	-	636
Total Contractual Cash Obligations	$ 603	$ 252	$ 44	$ -	$ 899

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note A to the Audited Consolidated Financial Statements. Certain of these policies are of particular importance to the portrayal of our financial position and results of operations, and require the application of significant judgment by management. We analyze our estimates, including those related to reserves, depletion and impairment of oil and gas properties, and the ultimate utilization of the deferred tax asset, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements:

Successful Efforts Method of Accounting

We account for our natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells, costs to acquire mineral interests and 3-D seismic costs are capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses including 2-D seismic costs and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense, net of salvage value, if and when the well is determined not to have found reserves in commercial quantities.

When an entire interest in an unproved property is sold, a gain or loss is recognized for the difference between the carrying value of the property and the sales price. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, the asset is relieved along with the corresponding accumulated depreciation, depletion, and amortization. When compared with the sales price a resulting gain or loss is recognized in income.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and ultimately deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment or recompletion of the wells at later dates. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on operational results reported when we are entering a new exploratory area in hopes of finding an oil and gas field that will be the focus of future development. The initial exploratory wells may be unsuccessful and will be expensed.

Reserve Estimates

Our estimates of oil and gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows depend upon a number of variable factors and assumptions, all of which may in fact vary considerably from actual results. These factors and assumptions include historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover gas costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of economically recoverable quantities of oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures, with respect to our reserves, will likely vary from estimates and such variances may be material. We contract with independent engineering firms to provide reserve estimates for reporting purposes.

Impairment of Oil and Gas Properties

We review our oil and gas properties for impairment at least annually and whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of our oil and gas properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and gas properties to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected.

Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require us to record an impairment of the recorded book values associated with oil and gas properties. We have recognized impairments in both the current and prior years and there can be no assurance that impairments will not be required in the future.

Income Taxes

We are subject to income and other similar taxes on our operations. Estimates are required when recording income tax expense or benefit. These estimates are necessary because: (a) income tax returns are generally filed many months after the close of the year; (b) tax returns are subject to audits that can take years to complete; and (c) future events often impact the timing for recognition of income tax expenses or benefits. During 2005, we utilized the federal income tax net operating loss carryforwards and other deductible differences available from prior years to reduce our current taxes. We routinely evaluate all deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized, or if likely realization may be many years in the future. A valuation allowance was not required at December 31, 2005.

Commodity Hedging Contracts

All of our price-risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." These derivative instruments are intended to hedge our price risk and may be considered hedges for economic purposes, but certain of these transactions may or may not qualify for cash flow hedge accounting. All derivative instrument contracts are recorded on the balance sheet at fair value. We have elected to account for certain of our derivative contracts as investments as set out under SFAS No. 133. Therefore, the changes in fair value in those contracts are recorded immediately as unrealized gains or losses on the Consolidated Statement of Operations. The change in fair value for the effective portion of contracts designated as cash flow hedges is recognized as Other Comprehensive Income (Loss) as a component in the Stockholders' Equity section of the Consolidated Balance Sheets.

NEW ACCOUNTING STANDARDS

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement 123R, "Share-Based Payment," which requires all companies to measure compensation cost for all share-based payments (including employee stock options) at fair value, effective for public companies for interim or annual periods beginning after June 15, 2005. The SEC further delayed the effective date of this FASB statement. We adopted the Statement effective January 1, 2006. We expect to record compensation expense of approximately $0.1 million during 2006 for options currently granted. There are no currently outstanding options or warrants for which compensation expense will be recorded after 2006. However, we granted restricted stock in January 2006 to directors and employees that will result in compensation expense of approximately $1.1 million in 2006, $1.2 million in 2007, and $0.8 million in 2008.

In April 2005, the FASB issued FSP FAS 19-1 to amend SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." The amendment allows continued capitalization of exploratory well costs beyond one year from the completion of drilling under certain circumstances. Circumstances for continued capitalization require that the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP FAS 19-1 also amended SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the consolidated financial statements. The Company adopted the new requirements during the second quarter of 2005. The adoption of FSP FAS 19-1 did not impact the Company's consolidated financial position or results of operations.

Sarbanes-Oxley Section 404 Implementation

Presented in Item 9A of this annual report is the second "Management Report On Internal Control Over Financial Reporting." Section 404 of the Sarbanes-Oxley Act of 2002 requires this report. In anticipation of the extensive work involved with complying with these requirements for the first time, in late 2003 our Board of Directors authorized management to engage an outside consulting firm to assist management in this project. In January 2004, after interviewing several firms, management and the Board selected Grant Thornton LLP to assist with the project. Grant Thornton assisted management with the review and update of existing documentation of internal controls, and facilitated the necessary steps to complete the evaluation of the adequacy and effectiveness of these controls for 2004. Management and the Board have a long-standing commitment to excellence in compliance and controls. This created an environment that fostered good control practices. A number of improvements to process flow were made during 2004, primarily related to systems. For 2005, we completed the work with the help of contract labor and again found our system of internal controls adequate and effective. No material changes to internal controls over financial reporting were necessary during 2005.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

***Commodity Risk*:** Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Prices have fluctuated significantly over the last five years and such volatility is expected to continue, and the range of such price movement is not predictable with any degree of certainty. While we have been party to forward-sale contracts from time to time in the past, no such forward sale agreements were in place for 2004 or 2005. However, we had in place ratio swap agreements that hedged approximately 40% of our monthly production as of the inception of the hedge on October 1, 2004. These swap agreements expired in October 2005. In March and June of 2005, we entered into additional financial price hedges, extending coverage for the similar monthly volumes through April of 2007. We had natural gas derivatives covering November 2005 through April 2007 in place for a portion of 2005. These gas hedges were terminated in October 2005 with a total cash payment of approximately $9.9 million. The remaining hedges are described in the table below. A 10% fluctuation in the price received for oil and gas production would have an approximate $3.9 million impact on our annual revenues based on 2005 sales volumes.

Derivative Contracts at Year End:

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Volumes Per Per Month
Crude Oil:					
03/05 *(1)*	Fixed Price Swap	11/01/2005	10/31/2006	$49.40	15,000 Bbl
06/05 *(1)*	Fixed Price Swap	11/01/2006	04/30/2007	$56.70	13,000 Bbl

(1) The fair value of our outstanding transactions is presented on the balance sheet by counterparty. The balance is shown as current or long-term based on management's estimate of the amounts that will be due in the relevant time periods at currently predicted price levels.

We entered into monthly Basis Swaps (mBS), for two months in 2005, to cover price exposure for certain new physical purchase contracts that used an average daily gas price rather than the first of the month index prices. The mBS agreements were established at the beginning of each month for the purchase volume expected at the daily gas price for the month. No receivable or payable for the settlement of those contracts remains on the Consolidated Balance Sheets. The net gain on the contract reduced Gas Gathering Operations expense on the Consolidated Statements of Operations. Effective October 1, 2005, we amended the contracts to use first of the month index prices; therefore we no longer use mBS contracts.

The Consolidated Balance Sheet at December 31, 2005, includes a total liability for derivative mark-to-market losses of $2.5 million divided between the "Accrued derivative obligation - current" and "Accrued derivative obligation - long-term" line items, as well as a $0.2 million liability for "Derivative settlements payable" in the "Current Liabilities" section. A derivative mark-to-market loss of $2.1 million was recognized on the Consolidated Statement of Operations in 2005. At the end of February 2006, the valuation of the remaining hedges is an unrealized liability of approximately $2.5 million.

Interest Rate Risk**:** We have borrowed funds under our Revolving Credit Facility with Guaranty Bank, with interest based on LIBOR rates plus an applicable margin. At March 3, 2006, we had $4.6 million in total borrowings under the Facility, with an average interest rate of 6.78%. At our current borrowing level, an annualized 10% fluctuation in interest charged on the floating rate balance at March 3, 2006, would have negligible impact on our annual net income.

Financial Instruments**:** Our financial instruments consist of cash equivalents and accounts receivable. Our cash equivalents are cash investment funds that are placed with a major financial institution. Substantially all of our accounts receivable result from oil and gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, we have not experienced any significant credit losses on such receivables. See the Risk Factors section.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements and Notes thereto are set out in this Form 10-K commencing on page F-1.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

A review and evaluation was performed by our Chief Executive Officer (the "CEO") and Chief Financial Officer (the "CFO") of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K. Based on that review and evaluation, the CEO and CFO have concluded that our current disclosure controls and procedures, as designed and implemented, are effective. There have been no changes in the Company's internal controls or in other factors that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting since their evaluation. There were no material weaknesses identified in the course of the review and evaluation and, therefore, no corrective measures were required.

Management's Report On Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. In making this assessment, they used criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on this assessment, our management believes that, as of December 31, 2005, our internal control over financial reporting was effective based on those criteria.

Akin, Doherty, Klein & Feuge, P.C., the independent registered public accounting firm that audited our consolidated financial statements included in this report, has issued an attestation report on management's assessment of our internal control over financial reporting. Their report, which expresses unqualified opinions on management's assessment and on the effectiveness of our internal control over financial reporting as of December 31, 2005, is presented on the next page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To The Board of Directors And Stockholders of
The Exploration Company of Delaware, Inc. and Subsidiaries
San Antonio, Texas

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that The Exploration Company of Delaware, Inc. and Subsidiaries (collectively referred to as "The Exploration Company" or "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that The Exploration Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, The Exploration Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2005 and 2004 and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005, of The Exploration Company and our report dated March 10, 2006, expressed an unqualified opinion thereon.

/s/ Akin, Doherty, Klein & Feuge, P.C.

San Antonio, Texas
March 10, 2006

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this Item relating to our directors and nominees, executive officers and compliance with Section 16(a) of the Exchange Act is included under the captions "Proposal I -- Election of Directors," "Executive Officers" and "Compliance with Section 16(a) of the Securities Exchange Act" in our Proxy Statement for the 2006 Annual Meeting of Shareholders and is incorporated herein by reference. The Proxy Statement will be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Exchange Act of 1934, as amended, not later than 120 days after December 31, 2005.

In January 2004, we amended our "Code of Conduct for All Employees and Directors." This document was filed with the SEC as Exhibit 14 with its Form 10-Q for the period ended March 31, 2004, and is also available on our Web site, www.txco.com, under the Governance tab.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this section will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

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

The information required by this section will be contained in the Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Effective in March 2006, we hired Mr. M. Frank Russell as Vice President and General Counsel. Mr. Russell had been Managing Partner with Barton, Schneider, Russell and East, L.L.P. ("BSRE"). Mr. Russell, while at BSRE, served as our lead outside counsel. In 2005, we paid BSRE over $248,000 in legal fees, of which approximately $166,000 was allocated by BSRE to Mr. Russell. Additionally, in the first two months of 2006 BSRE allocated over $25,000 of the fees we paid them to Mr. Russell out of approximately $33,000 we paid BSRE.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this section will be contained in the Proxy Statement under the heading "Auditor Independence" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following documents are being filed as part of this annual report on Form 10-K after the signature page, commencing on page F-1.

(1) Consolidated Financial Statements:
Report of Independent Registered Public Accounting Firm.
Consolidated Balance Sheets, December 31, 2005 and December 31, 2004.
Consolidated Statements of Operations, Years Ended December 31, 2005, 2004 and 2003.
Consolidated Statements of Stockholders' Equity, Years Ended December 31, 2005, 2004 and 2003.
Consolidated Statements of Cash Flows, Years Ended December 31, 2005, 2004 and 2003.
Notes to Audited Consolidated Financial Statements.

(2) Financial Statement Schedules.
Schedule II - Valuation and Qualifying Reserves.

All other schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are omitted as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or Notes thereto.

(3) Exhibits:

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
3.1	Restated Certificate of Incorporation of The Exploration Company of Delaware, Inc.	X			
3.2	Amended and Restated Bylaws of The Exploration Company of Delaware, Inc.		S-8	3.1	05/10/2002
4.1	Registrant's Rights Agreement, which includes: as Exhibit A thereto, the Certificate of Designation of Series A Junior Participating Preferred Stock; as Exhibit B thereto, Form of Right Certificate; as Exhibit C thereto, Summary of Rights to Purchase Preferred Shares.		8-K	4.1	07/07/2000
4.2	Subscription Agreement among The Exploration Company of Delaware, Inc., Kayne Anderson Energy Fund II, L.P. and Gryphon Master Fund, L.P., dated as of August 1, 2003.		8-K	4.1	08/26/2003
4.3	Certificate of Designation of Redeemable Preferred Stock, Series B of The Exploration Company of Delaware, Inc.		8-K	4.2	08/26/2003
4.4	Rights Agreement, between the Registrant and Kayne Anderson Energy Fund II, L.P. and Gryphon Master Fund, L.P.		8-K	4.3	08/26/2003
4.5	Amendment to Subscription Agreement, dated August 5, 2003.		8-K	4.4	08/26/2003
4.6	Credit Agreement between the Registrant and Guaranty Bank, FSB, dated June 30, 2004.		10-Q	4	08/09/2004
4.7	First Amendment to Credit Agreement between the Registrant and Guaranty Bank, FSB as Lender, Effective as of March 24, 2005.		10-Q	4.1	05/10/2005
4.8	Waiver and Second Amendment to Credit Agreement, effective August 23, 2005.		10-Q	4.1	11/09/2005
4.9	Third Amendment to Credit Agreement between the Registrant and Guaranty Bank, FSB as Lender, Effective as of December 15, 2005.	X			
10.1*	Employment Agreement between the Registrant and James E. Sigmon dated October 1, 1984.		10-K	10.1	11/27/1985
10.2*	1995 Flexible Incentive Plan.		Def14A	A	04/28/1995
10.3*	Amendment to the 1995 Flexible Incentive Plan.		Def14A	Proposal II	02/02/1999
10.4*	Amendment to the 1995 Flexible Incentive Plan.		Def14A	Proposal IV	04/16/2001
10.5*	Amendment to the 1995 Flexible Incentive Plan.		Def14A	Proposal III	04/25/2003
10.6	Registrant's Audit Committee Charter, as revised in January 2004, filed as Exhibit 10.21 to registrant's Annual Report on Form 10-K, dated March 15, 2004.		10-K	10.21	03/15/2004
10.7	Energy Option Transaction Confirmation dated October 5, 2004, between the registrant and Macquarie Bank Limited OBU.		10-Q	10.1	11/09/2004
10.8	Letter of Credit Agreement dated October 7, 2004, between the registrant and Guaranty Bank.		10-Q	10.2	11/09/2004
10.9*	Sample of Amended and Restated Change of Control Letter Agreements issued to all employees during December 2004.		8-K	10.1	12/17/2004
10.10	Asset Exchange Agreement by and between Arrow River Energy, L.P. and the Registrant dated February 11, 2005.		10-Q	10.1	05/10/2005
10.11	Irrevocable Letter of Credit benefiting Coral Energy Holdings, L.P. issued March 7, 2005.		10-Q	10.2	05/10/2005
10.12	Purchase and Sale Agreement by and between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.1	11/09/2005

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
10.13	Assignment of Bill of Sale and Conveyance - Southern Lands between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.2	11/09/2005
10.14	Partial Assignment of Oil, Gas and Mineral Leases - Northern Lands between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.3	11/09/2005
10.15	Assignment - Comanche Ranch between the Registrant and CMR Energy, L. P. effective September 1, 2005.		10-Q	10.4	11/09/2005
10.16	Assignment - Glen Rose Rights between the Registrant and CMR Energy, L. P. effective September 1, 2005.		10-Q	10.5	11/09/2005
10.17	Affidavit of Non-Foreign Status between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.6	11/09/2005
10.18	Seismic Data License Agreement between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.7	11/09/2005
10.19	Transition Services Agreement between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.8	11/09/2005
10.20	Partial Release of Liens and Security Interests between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.9	11/09/2005
10.21	Operating Agreement between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.10	11/09/2005
10.22	Release and Reassignment of Net Profits Interest between Registrant and Arrow River Energy L. P. effective September 1, 2005.		10-Q	10.11	11/09/2005
10.23*	Summary of compensation changes for directors and named executives for 2006.		8-K	10	12/30/2005
10.24*	Compensation change for a named executive for 2006.		8-K		01/17/2006
10.25*	Compensation arrangements for directors and named executives for 2006.		8-K		02/01/2006
14.1	Code of Ethical Conduct for Senior Officers and Financial Managers.		10-K	14	03/15/2004
14.2	Code of Conduct for All Employees and Directors.		10-Q	14	05/10/2004
23.1	Consent of Akin, Doherty, Klein & Feuge.	X			
23.2	Consent of DeGolyer and MacNaughton	X			
23.3	Consent of Cobb & Associates	X			
23.4	Consent of Netherland, Sewell & Associates, Inc.	X			
31.1	Certification of Chief Executive Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.	X			
31.2	Certification of Chief Financial Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.	X			
32.1+	Certification of Chief Executive Officer required pursuant to 18 U.S.C. Section 1350 as required by the Sarbanes-Oxley Act of 2002.	X			
32.2+	Certification of Chief Financial Officer required pursuant to 18 U.S.C. Section 1350 as required by the Sarbanes-Oxley Act of 2002.	X			

* Management contract or compensatory plan or arrangement.

\+ This exhibit shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE EXPLORATION COMPANY OF DELAWARE, INC.
Registrant

March 16, 2006

By: /s/ James E. Sigmon
James E. Sigmon, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ Stephen M. Gose, Jr. Stephen M. Gose, Jr.	Chairman of the Board of Directors	March 16, 2006
/s/ James E. Sigmon James E. Sigmon	President and Director (Principal Executive Officer)	March 16, 2006
/s/ Michael J. Pint Michael J. Pint	Director	March 16, 2006
/s/ Robert L. Foree, Jr. Robert L. Foree, Jr.	Director	March 16, 2006
/s/ Alan L. Edgar Alan L. Edgar	Director	March 16, 2006
/s/ Dennis B. Fitzpatrick Dennis B. Fitzpatrick	Director	March 16, 2006
/s/ Jon Michael Muckleroy Michael M. Muckleroy	Director	March 16, 2006
/s/ P. Mark Stark P. Mark Stark	Chief Financial Officer Vice-President-Finance (Principal Financial and Accounting Officer)	March 16, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
The Exploration Company of Delaware, Inc. and Subsidiaries
San Antonio, Texas

We have audited the consolidated balance sheets of The Exploration Company of Delaware, Inc. and Subsidiaries (collectively referred to as "The Exploration Company" or "Company") as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Exploration Company as of December 31, 2005 and 2004, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2005, in conformity with U. S. generally accepted accounting principles.

Our audits referred to above included audits of the financial statement schedule listed under Item 15. In our opinion, this financial statement schedule presents fairly, in all material respects, in relation to the financial statements taken as a whole, the information required to be set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of The Exploration Company's internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control -- Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 10, 2006 expressed an unqualified opinion on management's assessment of internal control over financial reporting and an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ Akin, Doherty, Klein & Feuge
AKIN, DOHERTY, KLEIN & FEUGE, P.C.
San Antonio, Texas
March 10, 2006

THE EXPLORATION COMPANY
Consolidated Balance Sheets
(in thousands)

	December 31	
	2005	**2004**
Assets		
Current Assets		
Cash and equivalents	**$6,083**	$3,118
Accounts receivable:		
Joint interest owners	**2,834**	1,737
Oil and gas sales	**6,510**	7,249
Prepaid expenses and other	**1,620**	800
Accrued derivative asset - current	**-**	134
Total Current Assets	**17,047**	13,038
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	**84,467**	94,836
Other Assets		
Deferred tax asset	**7,242**	5,233
Other assets	**780**	1,130
Total Other Assets	**8,022**	6,363
Total Assets	**$109,536**	$114,237

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Balance Sheets
(in thousands)

	December 31	
	2005	**2004**
Liabilities And Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	**$10,003**	$10,340
Undistributed revenue	**2,479**	1,062
Current income taxes payable	**4,952**	15
Other payables and accrued liabilities	**4,297**	5,435
Derivative settlements payable	**151**	49
Accrued derivative obligation - short-term	**2,084**	-
Long-term debt, current portion	**262**	1,666
Total Current Liabilities	**24,228**	18,567
Long-Term Liabilities		
Long-term debt, net of current portion	**1**	17,099
Accrued derivative obligation - long-term	**461**	-
Redeemable preferred stock, Series B (redemption value - $16 million)	**-**	10,991
Accrued dividends - preferred stock	**-**	218
Asset retirement obligation	**1,565**	1,680
Total Long-Term Liabilities	**2,027**	29,988
Stockholders' Equity		
Preferred stock; authorized 10,000,000 shares, Series A, -0- shares issued and outstanding Series B, -0- and 16,000 shares issued and outstanding	**-**	-
Common stock, par value $0.01 per share; authorized 50,000,000 shares, issued 29,479,697 and 28,110,363 shares, and outstanding 29,379,897 and 28,010,563	**295**	281
Additional paid-in capital	**89,680**	84,010
Accumulated deficit	**(4,622)**	(18,363)
Accumulated other comprehensive loss, net of tax	**(1,826)**	-
Less treasury stock, at cost, 99,800 shares	**(246)**	(246)
Total Stockholders' Equity	**83,281**	65,682
Total Liabilities and Stockholders' Equity	**$109,536**	$114,237

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Operations

(in thousands, except earnings per share data)	Years Ended December 31 2005	2004	2003
Revenues			
Oil and gas sales	**$38,533**	$30,181	$24,391
Gas gathering operations	**28,430**	27,536	15,145
Other operating income	**37**	18	9
Total Revenues	**67,000**	57,735	39,545
Costs and Expenses			
Lease operations	**6,470**	5,460	4,408
Production taxes	**2,180**	1,588	1,501
Exploration expenses	**3,266**	2,449	2,187
Impairment and abandonments	**1,406**	2,355	2,523
Gas gathering operations	**28,312**	25,292	15,136
Depreciation, depletion and amortization	**12,597**	9,851	8,628
General and administrative	**5,439**	4,853	3,716
Total Costs and Expenses	**59,670**	51,848	38,099
Income from operations	7,330	5,887	1,446
Other Income (Expense)			
Interest income	**89**	32	27
Interest expense	**(2,920)**	(2,909)	(1,365)
Loan fee amortization	**(132)**	(83)	(18)
Derivative mark-to-market loss	**(2,128)**	(19)	-
Derivative settlements loss	**(9,115)**	-	-
Gain on sale of assets	**24,540**	-	-
Total Other Income (Expense)	**10,334**	(2,979)	(1,356)
Income before income taxes, minority interest and cumulative effect of change in accounting principle	**17,664**	2,908	90
Minority interest in income of subsidiaries	**-**	35	75
Income before income taxes and cumulative effect of change in accounting principle	**17,664**	2,943	165
Income tax expense	**3,923**	146	50
Cumulative effect of change in accounting principle, net of tax	**-**	-	74
Net Income	**$13,741**	$2,797	$41
Earnings Per Share:			
Basic earnings before cumulative effect of change in accounting principle	**$0.48**	$0.11	$0.01
Cumulative effect of change in accounting principle	**-**	-	(0.01)
Basic Earnings Per Share	**$0.48**	$0.11	$0.00
Diluted earnings before cumulative effect of change in accounting principle	**$0.48**	$0.10	$0.01
Cumulative effect of change in accounting principle	**-**	-	(0.01)
Diluted Earnings Per Share	**$0.48**	$0.10	$0.00
Weighted average number of common shares outstanding:			
Basic	**28,444**	26,066	20,781
Diluted	**28,885**	26,971	21,295

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Stockholders' Equity
(in thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Treasury Stock	Total
Balance at December 31, 2002	20,110	$201	$58,216	$(21,201)	$ -	$(246)	$36,970
Issuance of common stock - net of expenses of $401	2,133	21	5,742	-	-	-	5,763
Other adjustments	-	-	18	-	-	-	18
Net income for the year	-	-	-	41	-	-	41
Balance at December 31, 2003	22,243	222	63,976	(21,160)	-	(246)	42,792
Issuance of common stock - net of expenses of $1,237	5,867	59	19,797	-	-	-	19,856
Non-cash compensation	-	-	237	-	-	-	237
Net income for the year	-	-	-	2,797	-	-	2,797
Balance at December 31, 2004	28,110	281	84,010	(18,363)	-	(246)	65,682
Common stock options & warrants exercised	912	9	2,907	-	-	-	2,916
Issuance of common stock - net of expenses of $-0-	458	5	2,763	-	-	-	2,768
Net income for the year	-	-	-	13,741	-	-	13,741
Other comprehensive income (loss):							
Deferred hedge losses	-	-	-	-	(2,881)	-	(2,881)
Tax benefits of hedge losses	-	-	-	-	1,055	-	1,055
Balance at December 31, 2005	29,480	$295	$89,680	$(4,622)	$(1,826)	$(246)	$83,281

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Cash Flows
(in thousands)

	Years Ended December 31		
	2005	**2004**	**2003**
Operating Activities			
Net income	$13,741	$2,797	$41
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	12,597	9,851	8,628
Impairments and abandonments	1,406	2,354	2,523
Minority interest in income of subsidiaries	-	(35)	(75)
Gain on sale of assets	(24,540)	-	-
Deferred income taxes	(928)	-	-
Cumulative effect of change in accounting principle	-	-	74
Non-cash interest expense and accretion of liability - redeemable preferred stock	684	1,016	677
Non-cash compensation expense	-	237	-
Non-cash derivative mark-to market (gain) loss	2,128	(134)	-
Payment to terminate cash flow hedge	(2,356)	-	-
Changes in operating assets and liabilities:			
Receivables	(984)	(4,147)	280
Prepaid expenses and other	(469)	(81)	(216)
Accounts payable and accrued expenses	4,981	4,589	3,226
Net cash provided by operating activities	6,260	16,447	15,158
Investing Activities			
Development and purchases of oil and gas properties	(52,440)	(39,335)	(36,071)
Purchase of other equipment	(37)	(224)	(397)
Proceeds from sale of oil and gas properties	78,002	-	-
Changes in minority interests	-	(159)	186
Net cash provided (used) by investing activities	25,525	(39,718)	(36,282)
Financing Activities			
Proceeds from common stock transactions, net of expenses	5,683	18,620	5,781
Proceeds from issuance of redeemable preferred stock, net of offering costs	-	-	9,230
Proceeds from bank credit facility	15,001	19,099	13,200
Payments on bank credit facility	(32,099)	(17,295)	(5,000)
Payments on installment and other obligations	(1,761)	(593)	(1,230)
Proceeds from installment and other obligations	356	377	2,990
Redemption of preferred stock	(16,000)	-	-
Net cash provided (used) by financing activities	(28,820)	20,208	24,971
Change in Cash and Equivalents	2,965	(3,063)	3,847
Cash and Equivalents at Beginning of Year	3,118	6,181	2,334
Cash and Equivalents at End of Year	$6,083	$3,118	$6,181
Supplemental Disclosures			
Cash paid for interest	$3,224	$ 3,011	$ 1,200
Cash paid for income taxes	158	-	-

See notes to audited consolidated financial statements.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations: The Exploration Company of Delaware, Inc., d.b.a. The Exploration Company ("TXCO" or "Company") is an independent energy company engaged in the acquisition, exploration, development and production of oil and gas properties. The Company's primary focus is on developing oil and gas reserves on properties located in Texas. The Company also owns properties in South Dakota, North Dakota and Montana.

Consolidation: The financial statements include the accounts of the Company and its majority-owned subsidiaries. The subsidiaries own and operate a gas gathering system that is utilized by the Company for delivery of natural gas from its Texas properties, as well as the delivery of natural gas produced by third parties. All significant intercompany balances and transactions have been eliminated in consolidation.

Revenue Recognition: The Company recognizes oil and gas revenue from its interest in producing wells as the oil and gas is sold to third parties. Gas gathering operations revenues are recognized upon delivery of the product to third parties.

Reclassifications: Certain amounts for 2004 and 2003 have been reclassified to conform to the 2005 presentation.

Cash and Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less to be cash and equivalents.

Accounts Receivable: Accounts receivable are reported at outstanding principal net of an allowance for doubtful accounts of approximately $27,000 at December 31, 2005, 2004 and 2003. The allowance for doubtful accounts is generally determined based on the Company's historical losses, as well as a review of specific accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible. The Company normally does not charge interest on accounts receivable.

Oil and Gas Properties: The Company uses the successful efforts method of accounting for its oil and gas activities. Costs to acquire mineral interests, developmental 3-D seismic costs, development wells, and costs to drill and equip exploratory wells that find proved reserves are capitalized. Costs, net of salvage value, for exploratory wells that do not find proved reserves, geological and geophysical costs, 2-D seismic costs, and costs of carrying and retaining unproved properties are expensed as incurred.

Management considers 3-D seismic shoots over the proved area of an oil or gas reservoir as developmental in nature. The Company uses its 3-D seismic database when selecting drilling sites, assessing recompletion opportunities, determining the cause when performance of a producing property is not as expected, as well as qualifying reservoir size and determining probable extensions and/or drainage areas for existing fields. The Company amortizes the cost of its capitalized developmental 3-D seismic shoots over a 60-month period.

Any well not drilled within the proved area of an oil or gas reservoir targeting a known productive depth is considered exploratory. Costs for exploratory wells in-progress are capitalized until a determination is made that no proven reserves are likely to be realized from the well's various potential intervals. If the determination is made that no proven reserves are likely to be realized from a target interval, the costs associated with that target interval are expensed. Costs associated with wells having several potential intervals remain capitalized until the determination of proven reserves is made for the final interval. Costs attributed to lower zones may be written off while upper zones remain in-progress due to planned re-completion efforts.

Depreciation, depletion and amortization ("DD&A") of oil and gas properties is computed using the unit-of-production method based upon recoverable reserves as determined by the Company's independent reservoir engineers. Depletion of coalbed methane properties begins following the dewatering phase of each coalbed methane project. Oil and gas properties are periodically assessed for impairment. If the unamortized capitalized costs of proved properties are in excess of the undiscounted future cash flows before income taxes, the property is impaired. Future cash flows are determined based on management's best estimate and may consider changes in prices for the product as considered most likely to occur in future periods. Unproved properties are also evaluated periodically and, if the unamortized cost is in excess of estimated fair value, impairment is recognized.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

Other Property and Equipment: Other property and equipment is recorded at cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets ranging from five to fifteen years. Major renewals and betterments are capitalized while repairs are expensed as incurred.

Federal Income Taxes: The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences. Accordingly, deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse.

Earnings Per Share: Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options.

Concentrations of Credit Risk: The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and accounts receivable. The Company places its temporary cash investments with major financial institutions which, from time-to-time, may exceed federally insured limits, and believes the risk of loss is minimal. Substantially all of the Company's accounts receivable result from oil and gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, the Company has not experienced credit losses on such receivables.

Commodity Hedging Contracts: The Company occasionally enters into derivative contracts, primarily options and swaps, to hedge future natural gas and crude oil production in order to mitigate the risk of market price. All derivatives are recognized on the balance sheet and measured at fair value (marked to market). The Company determines the accounting policy of its hedges on a case by case basis. Unrealized changes in the fair value of derivatives classified as investments are recognized in earnings, while unrealized changes in the fair value of derivatives classified as cash flow hedges are recognized as other comprehensive income or loss directly as a component in Stockholders' Equity. Gains and losses on hedge instruments settled are included in Other Income.

Fair Value of Financial Instruments: The following methods and assumptions were used to estimate the fair value of each class of financial instrument held by the Company:

- Current assets and current liabilities -- The carrying value approximates fair value due to the short maturity of these items.
- Long-term debt -- The fair value of the Company's long-term debt is based on secondary market indicators. Since the Company's debt is not quoted, estimates are based on each obligation's characteristics, including remaining maturities, interest rate, credit rating, collateral, amortization schedule and liquidity. The carrying amount approximates fair value.
- Commodity hedging contracts -- The Company's derivative instruments are adjusted to, and recorded at, fair value on the balance sheet.

Use of Estimates: The preparation of financial statements in conformity with U. S. generally accepted accounting principles requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates that may significantly impact the Company's financial statements include reserves, depletion and impairment on oil and gas properties, and the ultimate utilization of the deferred tax asset.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

Accounting for Stock Based Compensation: At December 31, 2005, the Company has a stock-based employee compensation plan that is described more fully in the Stockholders' Equity footnote. The Company accounted for this plan under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations through year-end 2005. No stock-based employee compensation cost related to stock options is normally reflected in net income, as all options granted under the plan had an exercise price equal to, or greater than, the market value of the underlying common stock on the date of grant. However, in 2004, the expiration date of an option and a warrant were extended for one year, resulting in the recognition of $237,333 in non-cash compensation expense. See paragraph 3 of "Recent Accounting Pronouncements" below for disclosure of upcoming changes in accounting for stock compensation.

The following table illustrates the effect on net income and earnings per share as if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation for the years ended December 31:

(in thousands, except earnings per share data)	**2005**	**2004**	**2003**
Net income as reported	$13,741	$2,797	$41
Deduct: Total stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects	(342)	(284)	(764)
Pro forma earnings (loss)	$13,399	$2,513	$(723)
Earnings (loss) per common share:			
Basic, as reported	$0.48	$0.11	$0.00
Basic, pro forma	0.47	0.10	(0.03)
Diluted, as reported	0.48	0.10	0.00
Diluted, pro forma	0.46	0.09	(0.03)

Government Regulations: The Company's oil and gas operations are subject to federal, state and local provisions regulating the discharge of materials into the environment. Management believes that its current practices and procedures for the control and disposition of such wastes substantially comply with applicable federal and state requirements.

401(k) Plan: During 2004, the Company instituted a 401(k) plan covering substantially all employees with over three months of service and 21 years of age. At its discretion, the Company may match a certain percentage of the employees' contributions to the Plan. The matching percentage is determined annually by the Board of Directors. Contributions to the Plan by the Company totaled $77,700 in 2005 and $35,500 in 2004.

Restoration, Removal and Environmental Matters: The estimated costs of restoration and removal of producing property well sites are accrued when it is probable that a liability has been incurred and the amount of remediation costs can be reasonably estimated. For wells drilled during the year, the liability is recognized, based on target depth, as the wells are spud. See Note D.

Recent Accounting Pronouncements: *FAS 123R:* In December 2004, the FASB issued Statement 123R, "Share-Based Payment (Revised 2004)" ("SFAS No. 123R"), effective for public companies for annual periods beginning after June 15, 2005. SFAS No. 123R eliminates the ability to account for stock-based compensation using APB 25 and requires that these transactions be recognized as compensation cost in the income statement based on their fair values on the date of grant. The transition provisions require the "modified prospective method" be applied to all new or modified awards and the remaining expense for unvested options. The expected impact to the Company for options and warrants currently granted is expected to be approximately $130,000 in 2006, and $0 during 2007, as all unvested options complete their vesting during 2006.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

FSP FAS 19-1: In April 2005, the FASB issued FSP FAS 19-1 to amend SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." The amendment allows continued capitalization of exploratory well costs beyond one year from the completion of drilling under certain circumstances. Circumstances for continued capitalization require that the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP FAS 19-1 also amended SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the consolidated financial statements. The Company adopted the new requirements during the second quarter of 2005. The adoption of FSP FAS 19-1 did not impact the Company's consolidated financial position or results of operations.

NOTE B - PROPERTY AND EQUIPMENT

Property and equipment consists of the following at December 31:

(in thousands)	**2005**	**2004**
Oil and gas properties	$124,511	$131,329
Other property and equipment	1,952	1,967
Total Property and Equipment	126,463	133,296
Accumulated depreciation, depletion and amortization	(39,593)	(35,440)
Reserve for impairment on unproved properties	(2,403)	(3,020)
Net Property and Equipment	$84,467	$94,836

Subsequent Acquisition: On March 10, 2006, the Company closed on the purchase of a drilling rig and other personal property and equipment from Ada Energy Services, LLC. The consideration for the purchase was $4.3 million.

NOTE C - LONG-TERM DEBT

Long-term debt consists of the following at December 31:

(in thousands)	2005	2004
Note payable to a financial institution under bank credit facility (see below), with interest at LIBOR or prime plus applicable margin, monthly payments of interest only, with maturity in 2008, and collateralized by all of the Company's proven oil and gas properties.	$1	$17,099
Installment notes to finance company on insurance policies, with interest from 6.00% to 7.95%, monthly installments of $34, with final payment in 2006, and unsecured.	262	-
Note payable to financing company, with interest at 12.61%, due in monthly installments of $22, with final payment in 2005, and collateralized by compressor equipment.	-	70
Note payable to an individual, with interest at 4.25%, annual installments of $1,406, with final payment in 2005, and unsecured.	-	1,349
Note payable to financing company, with interest at 11.85%, monthly installments, with final payment in 2005, and collateralized by office equipment.	-	4
Installment notes to insurance company, with interest from 4.45% to 8.75%, monthly installments of $36, with final payment in 2005, and unsecured.	-	243
Total long-term debt	263	18,765
Less current portion	(262)	(1,666)
Long-term portion of debt	$1	$17,099

The following is a schedule of principal maturities of long-term debt as of December 31, 2005:

Year Ended December 31,	Amount
	(in thousands)
2006	$262
2007	-
2008	1
	$263

Bank Credit Facility: The Company has a $50 million senior secured revolving credit facility with Guaranty Bank (the "Facility" or "credit facility"). The Facility was entered into in 2004 and expires in June 2008. It replaced TXCO's prior $25 million credit facility with Hibernia National Bank, which was scheduled to mature in 2006.

The credit facility is collateralized by all of the Company's proven oil and gas properties, had an initial borrowing base of $12.3 million, based on then current levels of TXCO's oil and gas reserves, and features semi-annual redeterminations. The borrowing base was subsequently increased based on reserves, and amendments were made during 2005 that modified the covenant terms and extended the termination date through June 2008. At December 31, 2005, the borrowing base, inclusive of traunche A and traunche B, stood at $29.0 million. The unused borrowing base at March 3, 2006, was $24.4 million with $4.6 million outstanding at an average interest rate of 6.78%. Interest under the Facility is based on, at TXCO's option, (a) the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 2.00% to 2.50% or (b) prime plus an applicable margin ranging from 0.00% to 0.25%. The Facility provides the lender a commitment fee equal to 0.5%, per annum on the unused borrowing base.

NOTE C - LONG-TERM DEBT - continued

The Facility contains additional terms and conditions consistent with similarly positioned companies. These conditions include various restrictive covenants such as minimum levels of interest coverage, tangible net worth and current ratio, a maximum debt to EBITDAX ratio, restricting the payment of dividends other than the dividends payable under the redeemable preferred stock, and prohibiting a change of control or incurring additional debt. The Facility's requirement for hedging a percentage of production, when borrowing under the Facility exceeded 50% of the borrowing base was removed during 2005. At December 31, 2005, the Company was in compliance with all covenants.

Redeemable Preferred Stock Series B: In August 2003, the Company issued 16,000 shares of mandatorily redeemable preferred stock. This stock was classified as debt, in accordance with SFAS 150. The shares were fully redeemed in 2005.

Letter of Credit Agreement: In connection with financial price hedges, the Company entered into a letter of Credit Agreement (L/C) with Guaranty Bank in October 2004. This agreement provides for the issuance of a Standby Letter of Credit (SLC) representing a Hedge Commodity Agreement or Rate Management Transaction issued outside of the original borrowing base as stated in the Facility. The agreement requires the payment of administrative fees ranging from 2.0% to 2.5% per annum of the face amount of the outstanding SLCs. The initial L/C amount was set at $1 million. Subsequently, additional SLC's were required in conjunction with the Company's derivatives. The total of SLC's outstanding at December 31, 2005 was $2.5 million. As of February 21, 2006, all SLC's were cancelled since they are no longer required by the counterparty to the remaining derivative agreements.

NOTE D - ASSET RETIREMENT COSTS AND OBLIGATIONS

Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. In addition, the associated asset retirement costs must be capitalized as part of the carrying amount of the long-lived asset.

The following is a reconciliation of the asset retirement obligation for the years presented in the Consolidated Balance Sheets:

	(in thousands)
Initial adoption, January 1, 2003	$1,300
Liabilities incurred	180
Liabilities settled	-
Accretion expense	58
Balance, December 31, 2003	$1,538
Liabilities incurred	120
Liabilities settled	-
Accretion expense	22
Balance, December 31, 2004	$1,680
Liabilities incurred	103
Liabilities transferred on properties sold	(218)
Accretion expense	-
Balance, December 31, 2005	$1,565

NOTE E - REDEEMABLE PREFERRED STOCK, SERIES B

In August 2003, the Company issued 16,000 preferred shares with a stated value of $1,000 each, and 2,133,333 common shares, in a private placement, raising approximately $15.0 million after offering costs. The Redeemable Preferred Stock was classified as a long-term liability on the balance sheet prior to its redemption in full during 2005.

The preferred stock yielded a dividend equal to 8% of stated value that was classified as interest expense, payable quarterly, for the first three years, and would have increased to 10% thereafter. It was redeemable at any time at the Company's option at the full stated value of $16 million, but was mandatorily redeemable in August 2009.

The preferred stock was initially recorded at its fair value of $9.8 million and accretion was being recorded to reach its full stated value over the six-year redemption period. The accretion was recorded as interest expense. The preferred shares were fully redeemed in 2005.

NOTE F - STOCKHOLDERS' EQUITY

Preferred Stock: The Company has authorized 10 million shares of preferred stock. At December 31, 2004, there were no Series A preferred shares issued and outstanding. The Board of Directors has not established terms of the stock. In 2003, the Company issued 16,000 shares of redeemable preferred stock, Series B, all of which was redeemed in 2005. See Note E.

Restricted Stock - 2005: The Company issued restricted common stock as partial payment for its Marfa Basin acquisition in October 2005.

Private Placement - 2004: In May 2004, TXCO closed on a private placement of 4.3 million shares of its common stock at a purchase price of $3.75 per share for net proceeds of $15.0 million. Included are warrants for an additional 1.3 million common shares exercisable at $4.25 per share. The warrants became exercisable in November 2004 and expire in May 2008. Purchasers were private, U.S.-based investment funds. Proceeds from the private placement were used to expand the Company's capital expenditure program, restore balance sheet liquidity, complement on-going operations and provide for general corporate purposes.

Private Placement - 2003: In August 2003, the Company issued 2.1 million shares of its common stock in conjunction with a private placement that included redeemable preferred stock. See Note E for further details. One-half of the common stock issued was restricted from trading for one year from issuance, and the remaining one-half of the common stock was restricted from trading for two years from issuance. The Company retained the option to repurchase up to one-half of the common stock at a purchase price of $6.00 per share for a period of two years from closing.

Stockholder Rights Plan: On June 29, 2000, the Company adopted a Rights Plan (the "Rights Plan") whereby a dividend of one preferred share purchase right (a "Right") was paid for each outstanding share of TXCO common stock. The Rights Plan is designed to enhance the Board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect shareholders against attempts to acquire the Company by means of unfair or abusive takeover tactics. The Rights will be exercisable only if a person acquires beneficial ownership of 15% or more of TXCO common stock (an "Acquiring Person"), or commences a tender offer which would result in beneficial ownership of 15% or more of such stock. When they become exercisable, each Right entitles the registered holder to purchase from TXCO .001 share of Series A Preferred Stock, subject to adjustment under certain circumstances.

Upon the occurrence of certain events specified in the Rights Plan, each holder of a Right (other than an Acquiring Person) may purchase, at the Right's then current exercise price, shares of TXCO common stock having a value of twice the Right's exercise price. In addition, if, after a person becomes an Acquiring Person, TXCO is involved in a merger or other business combination transaction with another person in which TXCO is not the surviving corporation, or under certain other circumstances, each Right will entitle its holder to purchase, at the Right's then current exercise price, shares of common stock of the other person having a value of twice the Right's exercise price. The Rights Plan generally may be amended by

NOTE F - STOCKHOLDERS' EQUITY - continued

the Company without the approval of the holders of the Rights prior to the public announcement by TXCO or an Acquiring Person that a person has become an Acquiring Person.

Unless redeemed by TXCO earlier, the Rights will expire on June 29, 2010. The Company will generally be entitled to redeem the Rights in whole, but not in part, at $0.01 per Right, subject to adjustment. No Rights were exercisable under the Rights Agreement at December 31, 2005.

Dividend Restriction: The Bank Credit Facility agreement limits dividends which may be declared and paid to such amounts as required under the terms of Redeemable Preferred Stock, Series B. The Agreement further limits the declaration, or payment, of dividends to no more than 50% of net income for the prior year-end, after consideration of the Series B requirements.

Commission Payment: In the first quarter of 2004, a commission of approximately $223,000 was paid to a Director of the Company under an agreement in place since prior to the appointment of the director to the Board. This fee was related to the exercise of warrants to purchase 1.2 million shares of the Company's common stock in January and February of 2004.

Stock Based Employee Compensation Plan: The Company granted options to its officers, directors, and key employees under its 1995 Flexible Incentive Plan (the "1995 Plan"), as amended, in prior years. The 1995 Plan was replaced during 2005 with the 2005 Stock Incentive Plan (the "2005 Plan"). The 2005 Plan allows for the future award of a maximum number of shares limited to 10% of the total number of then issued and outstanding shares of common stock for issuance, reduced by shares issued under, and outstanding grants issued under the 1995 Plan. These shares may be issued as the result of exercise of options granted or as restricted stock to management, directors, and key employees. At December 31, 2005, 2,937,990 shares were authorized for grant and 981,990 shares remained available for grant. All currently outstanding options have 10-year terms that vest and become fully exercisable based on the specific terms imposed at the date of grant.

Pro forma information included in Note A regarding net income and earnings per share as required by SFAS No. 123 is computed using a Black-Scholes option pricing model. The fair value for these options was estimated at the date of grant with the following weighted-average assumptions for the year ended December 31:

	2005	2004	2003
Risk-free interest rate	*	3.35%	4.17%
Expected dividend yield	*	0%	0%
Expected volatility of common stock	*	.47	.43
Expected weighted-average life of option	*	5 years	5 years

* No grants were awarded during 2005.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. The Company's employee stock options have characteristics significantly different from those of traded options, and changes in the subjective input assumptions can materially affect the fair value estimate. In management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its employee stock options.

In December 2004, the FASB issued Statement 123R, "Share-Based Payment," which requires all companies to measure compensation cost for all share-based payments (including employee stock options) at fair value, effective for public

NOTE F - STOCKHOLDERS' EQUITY-continued

companies for interim or annual periods beginning after June 15, 2005. See the discussion in Note A for the expected impact to the Company of options currently outstanding.

A summary of the Company's stock option activity and related information is as follows:

(shares in thousands)	Shares	Weighted Average Exercise Price	Weighted Average Fair Value of Options Granted	Exercisable at End of Period
Outstanding at December 31, 2002	1,463	$2.49		1,000
Granted	220	4.65	$1.74	
Outstanding at December 31, 2003	1,683	2.78		1,163
Granted	198	5.00	$1.92	
Exercised	(35)	2.81		
Forfeited	(30)	4.59		
Outstanding at December 31, 2004	1,816	2.99		1,218
Granted	-	-	N/A	
Exercised	(529)	3.15		
Forfeited	(33)	5.56		
Outstanding at December 31, 2005	1,254	$2.86		864

The following table summarizes information about the options outstanding at December 31, 2005:

(shares in thousands)	Options Outstanding			Options Exercisable	
Exercise Price	Number Outstanding	Wt.-Avg. Remaining Contractual Life	Wt.-Avg. Exercise Price	Number Exercisable	Wt.-Avg. Exercisable Price
$0.98	25	2.83 years	$0.98	25	$0.98
1.25	6	2.68 years	1.25	6	1.25
2.12	681	2.64 years	2.12	381	2.12
2.78	75	4.40 years	2.78	75	2.78
2.96	110	5.59 years	2.96	110	2.96
3.09	75	3.08 years	3.09	75	3.09
4.38	106	7.47 years	4.38	106	4.38
5.00	176	8.75 years	5.00	86	5.00
	1,254		$2.86	864	$2.90

Stock Warrants*:* The following is a summary of warrants outstanding at December 31, 2005:

Purpose of Warrants	Number of Shares *(in thousands)*	Range of Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
Financing	1,100	$3.00 - $4.25	$4.10	1.7 year

In January 2006, warrants were exercised to purchase 133,333 shares of the Company's common stock at $3.00 per share.

Also in January 2006, 320,000 shares of restricted stock were granted, under the 2005 Stock Incentive Plan, to directors and employees of the Company. Of these shares, 40,000 have a one-year vesting period, while the remaining 280,000 shares vest over a three-year period. Compensation expense will be recognized over the vesting periods and is expected to be $1.1 million in 2006, $1.2 million in 2007, and $0.8 million in 2008.

NOTE G - COMPREHENSIVE INCOME

Comprehensive income includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The components of comprehensive income are as follows for the years ended December 31, 2005 and 2004:

(in thousands)	2005	2004
Net income	$13,741	$2,797
Other comprehensive income (loss):		
Change in fair value of cash flow hedges	(2,881)	-
Income tax benefit of cash flow hedges	1,055	-
Total comprehensive income	$11,915	$2,797

NOTE H - EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator of the basic and diluted earnings per share computation:

(in thousands, except earnings per share data)	Shares	Income (Loss)	Per Share Amount
Year Ended December 31, 2005:			
Basic EPS:			
Net income	28,444	$13,741	$0.48
Effect of dilutive options	441	-	0.00
Dilutive EPS	28,885	$13,741	$0.48
Year Ended December 31, 2004:			
Basic EPS:			
Net income	26,066	$2,797	$0.11
Effect of dilutive options	905	-	0.01
Dilutive EPS	26,971	$2,797	$0.10
Year Ended December 31, 2003:			
Basic EPS:			
Net income	20,781	$41	$0.00
Effect of dilutive options	514	-	0.00
Dilutive EPS	21,295	$41	$0.00

NOTE I - OPERATING LEASES

The Company leases its primary office space through August 2007, and certain oil field equipment through November 2006. The Company incurred rent expense of approximately $791,000 in 2005, $582,000 in 2004 and $394,000 in 2003. Future minimum rentals under all non-cancelable leases are as follows:

Year Ended December 31,	Amount
(in thousands)	
2006	$341
2007	217
2008	34
2009	33
2010	11

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NOTE J - INCOME TAXES

The components of the Company's income taxes were as follows for the years ended December 31:

(in thousands)	2005	2004	2003
Current federal tax expense	$2,995	$146	$50
Deferred federal tax expense	928	-	-
Income tax expense	$3,923	$146	$50
Deferred tax assets:			
Tax net operating loss carryforwards	$ -	$1,200	$3,600
Impairment of oil and gas properties	6,955	6,100	4,700
Mark-to-market loss on cash flow hedges	738	-	-
Net deferred tax assets	7,693	7,300	8,300
Deferred tax liability:			
Depreciation differences	(451)	(425)	(75)
Gross deferred tax liability	(451)	(425)	(75)
Net deferred tax assets	7,242	6,875	8,225
Less valuation allowance	-	(1,642)	(2,992)
Deferred income tax asset	$7,242	$5,233	$5,233

The differences between the expected federal income taxes and the Company's actual taxes are as follows:

(in thousands)	2005	2004	2003
Expected federal tax expense	$6,535	$1,088	$61
Change in valuation allowance	(1,642)	(1,350)	225
Other changes, including statutory tax depletion and domestic production deduction	(970)	408	(236)
Income tax expense	$3,923	$146	$50

NOTE K - MAJOR CUSTOMERS

Sales to unrelated entities which individually comprised greater than 10% of total revenues are as follows:

	A	B	C	D	E	F
Year ended December 31, 2005	17%	14%	11%	11%	7%	- %
Year ended December 31, 2004	14%	5%	13%	2%	9%	13%
Year ended December 31, 2003	n/a	- %	18%	- %	20%	39%

NOTE L - COMMODITY HEDGING CONTRACTS AND ACTIVITY

Due to the volatility of oil and natural gas prices and requirements under TXCO's bank credit facility, the Company periodically enters into price-risk management transactions (e.g., swaps, collars and floors) for a portion of its oil and natural gas production. This allows it to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. These arrangements apply to only a portion of the Company's production, and provide only partial price protection against declines in oil and natural gas prices, and limit the Company's potential gains from future increases in prices. None of these instruments are used for trading purposes. On a quarterly basis, the Company's management sets all of the Company's price-risk management policies, including volumes, types of instruments and counterparties.

All of these price-risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." These derivative instruments are intended to hedge the Company's price risk and may be considered hedges for economic purposes, but certain of these transactions may or may not qualify for cash flow hedge accounting. All derivative instrument contracts are recorded on the Consolidated Balance Sheets at fair value. The Company has elected to account for certain of its derivative contracts as investments as set out under SFAS No. 133. Therefore, the changes in fair value in those contracts are recorded immediately as unrealized gains or losses on the Consolidated Statement of Operations. The change in fair value for the effective portion of contracts designated as cash flow hedges is recognized in Other Comprehensive Income (Loss) as a component in the Stockholders' Equity section of the Consolidated Balance Sheets. The gain or loss in Other Comprehensive Income will be reported on the Consolidated Statement of Operations as the hedged transactions occur (November 2006 through April 2007). The hedges are highly effective, and therefore, no hedge ineffectiveness was recorded.

The Company entered into monthly Basis Swaps (mBS), for two months in 2005, to cover price exposure for certain new physical purchase contracts that used an average daily gas price rather than the first of the month index prices. The mBS agreements were established at the beginning of each month for the purchase volume expected at the daily gas price for that month. No receivable or payable for the settlement of those contracts remains on the Consolidated Balance Sheets. The net gain on the contract reduced Gas Gathering Operations expense on the Consolidated Statements of Operations. Effective October 1, 2005, TXCO amended the contract to use first of the month index prices, therefore TXCO no longer uses mBS contracts.

During the fourth quarter of 2005, management terminated its derivative contracts for natural gas sales for the period beginning November 2005 and ending April 2007. The termination required a cash payment of approximately $9.9 million. In accordance with SFAS No. 133 guidance, the other comprehensive loss related to the derivatives will remain in the contra-equity account and be applied against revenue when the hedged transactions occur.

The following table lists contracts outstanding as of December 31, 2005.

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Barrels Per Month	Fair Value of Outstanding Derivative Contracts as of December 31, *(1)* 2005	2004
Crude oil (2):						***(in thousands)***	
Derivatives treated as investments:							
03/05	Fixed Price	11/01/2005	10/31/2006	$49.40	15,000	$(1,995)	-
Derivatives treated as cash flow hedges:							
06/05	Fixed Price	11/01/2006	04/30/2007	$56.70	13,000	(550)	-
	Total fair value of derivative contracts					$(2,545)	$134

(1) The fair value of the Company's outstanding transactions is presented on the balance sheet by counterparty. The balance is shown as current or long-term based on our estimate of the amounts that will be due in the relevant time periods at currently predicted price levels. Amounts in parentheses indicate liabilities.

(2) These crude oil hedges were entered into on a per barrel delivered price basis, using the West Texas Intermediate Index, with settlement for each calendar month occurring following the expiration date, as determined by the contracts.

NOTE M - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES

Capitalized Costs and Costs Incurred Relating to Oil and Gas Activities

The Company's investment in oil and gas properties is as follows at December 31:

(in thousands)	**2005**	**2004**
Proved properties	$91,768	$90,948
Less accumulated depreciation, depletion and amortization	(38,404)	(34,470)
Net proved properties	53,364	56,478
Unproved properties:		
Coalbed methane properties **(1)**	1,050	8,185
Drilling in-progress	21,738	19,468
Oil and gas leasehold acreage	9,955	12,728
Total unproved properties	32,743	40,381
Less reserve for impairment	(2,403)	(3,020)
Net unproved properties	30,340	37,361
Net capitalized cost	$83,704	$93,839

(1) The Company sold a 50% interest in most of these properties in February 2005, and the remaining 50% of the same properties in September 2005.

Costs incurred, capitalized, and expensed in oil and gas producing activities are as follows for the years ended December 31:

(in thousands, except per equivalent Mcf data)	**2005**	**2004**	**2003**
Property acquisition costs, unproved	$9,684	$11,107	$11,744
Property development and exploration costs:			
Conventional oil and gas properties	31,903	31,873	27,142
Coalbed methane properties	76	314	571
Gathering system	388	101	310
Depreciation, depletion and amortization	12,377	9,646	8,260
Depletion per equivalent Mcf of production	2.69	1.97	1.71

Oil and Gas Reserves (Unaudited)

The estimates of the Company's proved reserves and related future net cash flows that are presented in the following tables are based upon estimates made by independent petroleum engineering consultants. The Company's reserve information was prepared as of each respective year-end. There are many inherent uncertainties in estimating proved reserve quantities, projecting future production rates, and timing of development expenditures. Accordingly, these estimates are likely to change, as future information becomes available. Proved developed reserves are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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NOTE M - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES - continued

Changes in estimated net quantities of conventional oil and gas reserves, all of which are located within the United States, are as follows for the years ended December 31:

(in thousands)	2005	2004	2003
Proved developed and undeveloped reserves:			
Natural gas (MMcf):			
Beginning of year	17,701	15,624	14,675
Extensions and discoveries	5	6,432	5,037
Reserves purchased	-	557	671
Sales volumes	(2,222)	(2,975)	(2,108)
Revisions of previous engineering estimates	(2,844)	(1,937)	(2,651)
Reserves transferred	(2,984)	-	-
End of year	9,656	17,701	15,624
Crude Oil (MBbl):			
Beginning of year	3,374	2,129	1,479
Extensions and discoveries	522	1,396	1,115
Reserves purchased	-	-	1
Sales volumes	(397)	(321)	(454)
Revisions of previous engineering estimates	1,187	170	(12)
Reserves transferred	271	-	-
End of year	4,957	3,374	2,129
Proved developed reserves:			
Natural gas (MMcf):			
Beginning of year	13,087	9,896	6,213
End of year	7,846	13,087	9,896
Crude Oil (MBbl):			
Beginning of year	1,688	1,340	988
End of year	1,813	1,688	1,340

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved developed and undeveloped oil and gas reserves. Prices used to determine future cash inflows were based on the respective year-end weighted average sales prices utilized for the Company's proved developed reserves. The prices were $7.775, $6.06 and $5.77 per Mcf of gas and $57.75, $41.15 and $30.06 per barrel of oil as of December 31, 2005, 2004 and 2003. The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's reserves and the tax basis of proved oil and gas properties and available operating losses and temporary differences.

THE EXPLORATION COMPANY
Notes to Audited Consolidated Financial Statements
Years Ended December 31, 2005, 2004 and 2003

NOTE M - OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES - continued

(in thousands)	2005	2004	2003
Future cash inflows	$379,431	$246,073	$154,215
Future production and development costs	(167,659)	(113,353)	(65,263)
Future income tax expense	(53,419)	(25,152)	(14,802)
Future net cash flows	158,353	107,568	74,150
10% annual discount to reflect timing of net cash flows	(60,330)	(42,106)	(26,801)
Standardized measure of discounted future net cash flows relating to proved reserves	$98,023	$65,462	$ 47,349

The principal factors comprising the changes in the standardized measure of discounted future net cash flows are as follows for the years ended December 31:

(in thousands)	2005	2004	2003
Standardized measure, beginning of year	$65,462	$47,349	$38,147
Extensions and discoveries	19,410	46,763	34,608
Reserves purchased	-	2,533	1,591
Sales and transfers, net of production costs	(29,882)	(23,133)	(18,482)
Revisions in quantity and price estimates	62,177	2,547	(2,491)
Net change in income taxes	(12,598)	(5,862)	(2,209)
Accretion of discount	(6,546)	(4,735)	(3,815)
Standardized measure, end of year	$98,023	$65,462	$47,349

NOTE N - Selected Quarterly Financial Information (Unaudited)

(In thousands, except earnings per share data)	First	Second	Third	Fourth	Total
2005					
Total revenues	$14,617	$15,471	$17,136	$19,776	$67,000
Income from operations	1,161	568	1,431	4,170	7,330
Net income (loss)	(3,302)	(1,018)	15,288	2,773	13,741
Earnings Per Share: (1)					
Basic	$(0.12)	$(0.04)	$0.54	$0.10	$0.48
Diluted	$(0.12)	$(0.04)	$0.53	$0.09	$0.48
2004					
Total revenues	$11,367	$14,625	$15,317	$16,426	$57,735
Income from operations	807	1,144	1,330	2,606	5,887
Net income	69	372	600	1,756	2,797
Earnings Per Share: (1)					
Basic	$0.00	$0.02	$0.02	$0.06	$0.11
Diluted	$0.00	$0.01	$0.02	$0.06	$0.10

(1) Quarterly earnings per share are based on the weighted average number of shares outstanding during the quarter. Because of the increase in the number of shares outstanding during the quarters due to exercises of warrants and stock options, as well as newly issued shares, the sum of quarterly earnings per share may not equal earnings per share for the year.

THE EXPLORATION COMPANY
Schedule II - Valuation and Qualifying Reserves

(in thousands)	Balance Beginning of Period	Charged to Costs and Expense	Deductions	Balance End of of Period
Year Ended December 31, 2005				
Allowance for doubtful accounts, trade accounts	$ 27	$ -	$ -	$ 27
Impairment of oil and gas properties	3,020	1,007	(1,624)	2,403
Deferred tax asset valuation allowance	1,642	-	(1,642)	-
Year Ended December 31, 2004				
Allowance for doubtful accounts, trade accounts	$ 27	$ -	$ -	$ 27
Impairment of oil and gas properties	2,200	883	(63)	3,020
Deferred tax asset valuation allowance	2,992	-	(1,350)	1,642
Year Ended December 31, 2003				
Allowance for doubtful accounts, trade accounts	$ 27	$ -	$ -	$ 27
Impairment of oil and gas properties	1,488	762	(50)	2,200
Deferred tax asset valuation allowance	2,767	225	-	2,992