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, 2006

OR

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

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.)
777 E. Sonterra Blvd., Suite 350; San Antonio, Texas	**78258**
(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: **Common Stock, par value $0.01 per share**

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

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 ☑

On June 30, 2006 (the end of registrant's second quarter), the aggregate market value of the its common stock held by its non-affiliates was $323.7 million, based on the $10.66 per share closing price as reported on the NASDAQ Global Select Market.

The number of shares outstanding of the registrant's Common Stock as of March 13, 2007, was 33,272,279 with a closing price of $9.20.

Documents Incorporated by Reference: Portions of the Company's Proxy Statement for the Annual Stockholders' Meeting, to be held on May 11, 2007 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 that 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 forward-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 Global Select Market℠ 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: 777 E. Sonterra Blvd., Suite 350, San Antonio, Texas 78258, (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 or the General Counsel at the address above.

Also under the "Governance" menu of our Web site, 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, reconciliations of non-GAAP items and various supplemental information. The content on any Web site referred to in this Form 10-K is not incorporated by reference into this Form 10-K unless expressly noted.

As of December 31, 2006, we employed 77 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, exploitation, development, production and acquisition 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, exploitation and development programs. Our business strategy is to build stockholder 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 stockholder value includes maintaining a focus on our core business of oil and gas exploration, exploitation 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 focus primarily on the Maverick Basin and have successfully established a multi-year portfolio of drilling targets within this area. To support our growing asset base in the Maverick Basin, we own a 91-mile natural gas gathering system that 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 and exploitation targets within our core area of operations. We are well positioned to pursue new oil and gas reserves and expand our production base by 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.

In addition to our focus on our core oil and natural gas producing properties and higher margin exploration and exploitation activities in the Maverick Basin, we are evaluating opportunities in our 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.

We have taken another step in expanding beyond these core areas through the announcement of our proposed acquisition of Output Exploration, LLC, a privately held, Houston-based exploration and production firm. The core of the Output holdings is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk and Eagleford / Woodbine formations. Other Output holdings to be acquired include acreage in the mid-continent and gulf coast regions and shallow Gulf of Mexico waters. Closing is expected on or about April 2, 2007.

RECENT DEVELOPMENTS

2006 Drilling Activity Summary: We participated in drilling a total of 58 gross wells during 2006. Maverick Basin wells totaled 56, including 11 re-entries, while one new well was drilled in the Williston Basin and one re-entry was begun in the Marfa Basin. Of the 58 total wells through year-end, 41 were placed on production, one was completed as a water injection well, one well awaited transfer to an operating partner, four wells awaited hook-up, seven remained in various stages of completion or testing, two wells were waiting to be plugged and abandoned, and two continued drilling. Maverick Basin wells completed in 2006 include 40 producing oil, one producing natural gas, and one completed as a water injection well. The one Williston Basin well drilled is producing oil, while the one Marfa Basin well is in completion. Two of the four in-progress wells re-entered, and three wells that were in completion at the beginning of the year, resulted in producing oil well completions during 2006.

Reserve Growth: We continued our ongoing trend of annual reserve growth in 2006 by recording net proved reserve additions of 2.0 billion cubic feet equivalent ("Bcfe"). Combined with annual production of 5.9 Bcfe, our gross reserve additions for the year were 7.9 Bcfe. Estimated year-end proved oil and gas reserves reached 41.4 Bcfe, a 5.1% increase above the 39.4 Bcfe at year-end 2005. We achieved a 134.8% all-source reserve replacement rate in 2006.

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, exploitation and development targets for 2007, presented in descending depth order, include:

- developing production from our San Miguel oil sands;
- expanding waterflood oil production from the San Miguel interval on the Pena Creek lease;
- expanding oil and gas production from Georgetown horizontal wells;
- continued horizontal and vertical drilling for Glen Rose shoal and reef gas intervals;
- additional horizontal wells targeting Glen Rose porosity oil production;
- vertical wells targeting gas from the Pearsall Shale and Sligo formations; and
- exploration of the Barnett and Woodford shales in the Marfa Basin.

Each of these high-impact exploration, exploitation 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.

2007 Capital Expenditures Budget: Should our exploration, exploitation and development plans progress as projected, we expect continued growth of our oil and gas reserves and production levels in 2007. We established a range of $70 million to $75 million for our 2007 capital expenditure budget ("CAPEX"), with more than 90% earmarked for more than 90 wells targeting multiple horizons. In the Marfa Basin, which is prospective for the Barnett and Woodford shales, we have allocated approximately $3.0 million for one new well and a 3-D seismic acquisition program. Other items in the budget, including leasing and infrastructure projects, are earmarked for $10.4 million. Additional CAPEX expenditures of approximately $15 million are expected on properties to be acquired with the proposed acquisition of Output Exploration, LLC discussed below.

Our 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 2007, 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: We entered into an $80 million purchase and sale agreement ("2005 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. The 2005 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 ("Report").

Proposed Acquisition: On February 20, 2007, we signed a merger agreement to purchase Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase is $91.6 million in cash, subject to certain adjustments, and $4.0 million of TXCO common stock. The transaction, the largest in TXCO's history, will double our proved reserves and increase current oil and gas production by nearly two thirds. The core of the Output holdings is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk and Eagleford / Woodbine formations. Other Output holdings to be acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf of Mexico waters. Closing is expected on or about April 2, 2007. Additional information regarding our proposed acquisition of Output, including the merger agreement, is included in the Form 8-K that we filed with the SEC on February 26, 2007.

PRINCIPAL AREAS OF ACTIVITY

Oil and Gas Operations: During 2006, we spudded or re-entered a total of 56 wells in various horizons in the Maverick Basin, and one in each of the Williston and Marfa Basins. These totals compared to 51, one and none, respectively, in 2005. Of the 58 wells begun in 2006, 43 have been placed on production through February 2007, including 41 new oil wells in the Glen Rose, San Miguel, Georgetown, and Red River formations, and two gas wells completed in the Glen Rose and Pearsall formations, while one was converted to a salt water injection well and one was plugged and abandoned.

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. Increased oil and gas revenues due to higher average prices and increased oil sales volumes were partially offset by a decrease in Maverick Basin natural gas sales during 2006, resulting in an increase in net cash provided by operating activities to $24.7 million in 2006 from $6.3 million in 2005.

Our strategy remains focused on our core oil and natural gas producing properties and higher margin exploration, exploitation and development 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 2006, we had an average working interest ("WI") of over 84% on our Maverick Basin leasehold acreage (650,000 gross acres). 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.

Subsequent to year-end 2006, we acquired an interest in primarily shallow horizons under 85,681 acres in an agreement with EnCana Oil and Gas. This acreage includes rights through the Glen Rose interval under the entire acquisition, plus a 50% interest in more than 16,000 acres of the block through the Sligo formation. This acquisition brings our holdings to nearly 560,000 net acres in this Basin.

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 2006, we acquired an additional 45 square miles of 3-D seismic data. At year-end 2006 we had accumulated over 979 square miles of 3-D seismic data covering more than 94% 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 below.

The following table contains details by formation in descending depth order for our approximate working interest ownership in some of our Texas projects budgeted for 2007:

		Working Interest Range
1	San Miguel Oil Sands - Oil	50% to 100%
2	San Miguel Waterflood - Oil	100%
3	Georgetown - Oil and Gas	63% to 100%
4	Glen Rose Porosity Zone - Oil	50% to 100%
5	Other Glen Rose - Oil and Gas	48% to 100%
6	Pearsall Shale - Gas	12.5% to 100%
7	Barnett and Woodford Shales - Gas	50%

The expanding geophysical database, 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 Maverick Basin lease block remain very significant.

MAVERICK BASIN PLAYS

Glen Rose Oil: During 2006, our working interest in much of our non-operated, 100,000-acre Comanche Ranch lease was 75.5%. We have a proprietary 3-D seismic survey that covers the Comanche Ranch lease. 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 porosity, 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, low-sulfur oil is consistent throughout the entire area, which contains no gas. Our engineering staff 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.

Eight new wells and four re-entries were drilled on the Comanche Ranch during 2006 with our operating partner. Additionally, during 2006 we drilled or re-entered 19 Glen Rose oil wells on the adjacent Cage and Glass Ranches, where we hold a 100% WI. Of the combined 31 wells drilled or re-entered targeting the porosity zone, 21 were producing oil at year-end 2006, four were completed and awaiting hook-up, two were to be completed or re-completed, two were drilling, one was to be plugged and abandoned and one will be transferred to a partner. Since year-end, one additional 2006 well has begun production and one well was plugged and abandoned. By comparison, we drilled or re-entered 18 Glen Rose oil wells during 2005.

Glen Rose oil sales for 2006 totaled 689,000 barrels of oil ("BO") up from 236,000 BO during 2005. The combined number of wells drilled since the oil play's discovery in February 2002 stands at 71 through year-end 2006. Cumulative Glen Rose gross oil production since its discovery surpassed 3.6 million barrels of oil through February 2007. During the third and fourth quarters, our operations personnel attempted to improve on the economics of the play by reducing the water produced. In order to reduce the number of fractures encountered that extended into the water zone, new wells were drilled parallel to the known fracture systems rather than perpendicular to them as had been done in the past. Although six of these wells initially flowed oil, the wells started producing mostly water in a very short time period. These six wells will be re-entered and drilled across the fracture system. Future wells will be drilled perpendicular to the fracture system as has been successful in most of the wells previously drilled. The project remains profitable and economics should improve as we 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, 2006, for the Glen Rose oil porosity zone are estimated at 1.5 million BO, equivalent to 9.0 Bcfe, up from 1.2 million (7.4 Bcfe) for the prior year. We believe that significant additional proved reserves will be established in the future.

We spudded three porosity wells thus far in 2007. One well currently awaits completion while two wells continue drilling. Our 2007 CAPEX includes $36.0 million for 36 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 2007 of over 1.0 Bcf, and is still producing about 100 mcf per day ("mcfd"). Pursuant to our 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.

Since 2001, we have completed 29 horizontal Glen Rose gas wells, with two wells awaiting completion. We spudded one shoal well during 2005 and 2006 and they await re-completion. We spudded one new Glen Rose reef well during 2006, which is producing gas. Glen Rose gas sales for 2006 totaled 1.0 Bcf down from 1.4 Bcf during 2005. The field produced more than 13.5 Bcf since horizontal drilling techniques were first applied in 2001. At December 31, 2006, net proved gas reserves for Glen Rose were estimated at 7.7 Bcfe, down from 9.2 Bcfe for the prior year. Plans for 2007 include $7.6 million for drilling 12 Glen Rose shoal or reef wells. One Glen Rose shoal well and two reef wells have been spudded thus far in 2007, all of which remain in completion.

Georgetown: During 2006, we spudded one new Georgetown well and re-entered three wells, as compared to 16 Georgetown wells drilled or re-entered in 2005. Of the four 2006 Georgetown wells, three wells are producing oil, while one well remains in completion. Georgetown gas sales for 2006 totaled 52.5 mmcf, down from 727.7 mmcf during 2005 due to the 2005 Asset Sale in the third quarter of 2005, while Georgetown oil sales decreased to 13,200 BO from 49,800 BO in 2005. The current 2007 CAPEX budget includes $3.0 million for five new wells. We have re-entered one Georgetown well this year through February 2007.

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 0.3 Bcfe from 0.6 Bcfe at year-end 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. 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 2006, we drilled and successfully completed 15 infill wells targeting bypassed reserves. During 2005, we successfully completed five of the six wells spudded. San Miguel oil sales temporarily declined to 66,200 BO from 78,500 BO for the same periods due to remodeling the waterflood to change the injection patterns. Net proved reserves at year-end for this field were estimated at 4.0 million barrels, equivalent to 23.8 Bcfe, up from 3.6 million barrels (21.4 Bcfe) at year-end 2005. The 10,000-acre Pena Creek prospect is contiguous to our Comanche Ranch lease. The 2007 CAPEX budget includes $3.5 million for 11 new wells in the San Miguel waterflood.

Pearsall Shale: We participated in the drilling, completion and testing of our first vertical Pearsall Shale well in the Maverick Basin during 2006, which began producing gas during January 2007 at the rate of approximately 75 mcfd. The data gathering well is the first in a series targeting the gas resource play in a joint venture (50% WI) with EnCana Oil & Gas (USA), Inc. as operator. This represents our first major investment in this promising formation that underlies approximately 250,000 acres of our Maverick Basin deep-rights leaseholdings. The Pearsall Shale is an over-pressured shale play. Our 2007 CAPEX budget includes $4.8 million for drilling three new wells in the Pearsall Shale formation on our Chittim lease block in partnership with EnCana.

Oil Sands: The San Miguel Oil Sands feature ("Oil Sands") is prospective under our existing Maverick Basin acreage. Our reservoir engineers and geologists have estimated that there are 7 to 10 billion BO in place basin wide. Conoco and Mobil did pilot projects on the San Miguel Oil Sands in the late 1970's and early 1980's and achieved recoveries of over 50% with the use of steam injection. The Oil Sands are much like those found in Cold Lake Field in Canada. In 2005 we entered into a Participation Agreement that has resulted in a shared leasehold working interest with Newmex Energy (USA) Inc., a wholly-owned subsidiary of Pearl Exploration and Production, Ltd. (TSX Venture: "PXX") ("Pearl"). While we are the operator with a 50% WI, we are drawing on Pearl's technical expertise with similar projects in Canada. The Participation Agreement includes an Area of Mutual Interest that contains approximately 36,000 acres of our joint leasehold and calls for the drilling of three pilot wells at no cost to us. In addition, we hold a 100% WI in approximately 41,000 acres over the deposit.

To date, two initial pilot wells have been drilled and completed and a steam facility was constructed, at no cost to TXCO. Steam injection has begun. The first well has completed the initial steam injection, soak and production cycle. The bottomhole temperature needs to be approximately 350 to 400 degrees Fahrenheit to allow the oil to be productive. The first cycle raised the bottomhole temperature from 110 to 300 degrees Fahrenheit. The second cycle should raise the temperature enough to begin oil production. The second pilot well is in the initial steam injection phase. Based on the results from the pilot wells, our 2007 CAPEX budget includes $3.7 million for 21 San Miguel Oil Sands wells and related infrastructure.

Other Plays: During 2006, we drilled one lateral to the Pryor formation that is awaiting completion, down from six wells in other Maverick Basin formations during 2005. The 2007 CAPEX budget did not include funds for drilling in any other formations. One re-entry targeting the Austin Chalk formation was spud in February 2007, which remains at completion stage.

MARFA BASIN

The Marfa 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 acquired an interest in 140,000 gross acres in the Marfa Basin in 2005, and in 2006 brought in Continental Resources Inc. as our 50% partner. We re-entered one vertical well targeting the Woodford shale during 2006, which tested gas and awaits a fracturing procedure. Our 2007 CAPEX budget includes $3.0 million to shoot 3-D seismic data or drill one horizontal well targeting the Barnett shale.

WILLISTON BASIN

Through 2006, 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, 2006, we retained approximately 83,000 net acres in the Williston Basin. Most of our undeveloped leases in North Dakota will expire during 2007.

During 2006, we participated in the drilling of one new well (0.6% WI) in the Red River formation that is currently producing oil. In 2005 we participated in one new oil well in this formation. Our 2006 net sales for the Williston Basin totaled 22,100 BO and 45.0 mmcf, as compared to 31,200 BO and 58.3 mmcf in 2005. No funds have been included in the 2007 CAPEX for drilling in this basin.

OTHER AREAS

On February 20, 2007, we signed a merger agreement to purchase Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase is $91.6 million in cash, subject to certain adjustments, and $4.0 million of TXCO common stock. The transaction, the largest in TXCO's history, will double our proved reserves and increase current oil and gas production by nearly two thirds. The core of the Output holdings is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk and Eagleford/Woodbine formations. Other Output holdings to be acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf of Mexico waters. Closing is expected on or about April 2, 2007. Capital expenditures are expected to be approximately $15 million for 2007 for the newly acquired areas, which we anticipate will be funded through Output's cash flow.

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 2006. 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 2006, two purchasers of our oil and gas production and other natural gas sales accounted for 12% and 10% of total revenues. We believe that alternative purchasers could be found for such production at comparable prices if either of these major customers declined to purchase future production.

During 2006, we purchased and refurbished a drilling rig. The rig has a 750 horsepower drawworks and can drill vertical and horizontal wells up to a total measured depth of approximately 10,000 feet. It was placed into service in January 2007. The rig allows us to reduce drilling costs on our wells and facilitates our ability to meet our minimum drilling obligations.

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. While 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. 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. Since 2004 more than 94% of our revenues have been from production in Texas where 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.

In 2006, our effective tax rate (federal and state) was approximately 26.3% reflecting the tax election by TXCO Energy Corp., a wholly-owned subsidiary, to expense intangible drilling costs. In 2005, we fully utilized our tax net operating loss carryforwards, resulting in an effective tax rate (federal and state) of approximately 22%.

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 oil and gas pipelines, crude oil trucking, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities could harm our business. We transport our crude oil through pipelines and trucks that we do not own, and we deliver some of our natural gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future or may become inadequate for oil and gas volumes produced.

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 81% 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.

The prices we receive for our production and sales may actually vary from prices posted for national markets and exchanges for commodities. We sell our gas based on the Houston Ship Channel index. We sell our oil on the Flint Hills Resources postings. These prices may vary significantly from national markets for these commodities such as NYMEX. While the disparity between these markets is not significant today, these prices have diverged in the past and could diverge in the future.

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, exploitation, 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 not have 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 associated entities could adversely affect our business.

We do not operate all of our properties on our own. We may enter into partnering relationships with other entities over which we have little or no control. Because we have limited or no control over such entities, we may not be able to direct their operations, or 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.

If losses and liabilities from drilling and operating activities are not deemed fully covered by our insurance policies, it 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. The future net cash flows are based upon the prices received on December 31 of each year.

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 and other key employees. 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.

We currently have a significant acquisition in progress and it is possible that we will acquire additional entire businesses in the future. Potential risks involved in the acquisition of such businesses include the inability to satisfy closing conditions, 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 is 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 issue additional capital stock to raise capital, or as partial consideration in acquisitions, which would dilute current investors.

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. Further, we may issue additional shares of our capital stock to sellers in mergers or acquisitions as purchase consideration. Any such issuance will dilute the ownership percentage of the current holders of the Common Stock. In March 2006, we issued 3.0 million shares of our common stock in a private placement to raise additional capital. Further, a portion of the consideration for our proposed acquisition of Output Exploration, LLC is comprised of shares of our Common Stock.

Pursuant to our Restated Certificate of Incorporation, our board of directors has the authority to issue additional shares of common stock without approval of our stockholders, subject to applicable stock exchange requirements.

Our Restated Certificate of Incorporation permits our board of directors to issue preferred stock with rights greater than our Common Stock.

Although there are no current plans, arrangements, understandings or agreements to issue any preferred stock, our Restated 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 our stockholders. 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, and have other preferences to, our Common Stock.

The exercise of stock options or warrants would result in 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. As of March 13, 2007, there were outstanding under our1995 Flexible Incentive Plan options to purchase an aggregate 855,750 shares of our Common Stock. No stock options have been granted under our 2005 Stock Incentive Plan. Additionally at the same date, there were warrants to purchase 926,500 shares of our Common Stock outstanding.

Instituted in 1999, our Rights Plan and certain provisions in our Restated Certificate of Incorporation may inhibit a takeover of the Company.

- Our Rights Plan and certain provisions in our Restated Certificate of Incorporation could have the effect of discouraging a third party from making a tender offer or otherwise attempting to obtain control of the Company.
- Our Rights Plan, commonly referred to as a "poison pill," provides that when any person or group acquires beneficial ownership of 15% or more of Company common stock, or commences a tender offer which would result in beneficial ownership of 15% or more of such stock, holders of rights under the Rights Plan will be entitled to purchase, at the Right's then current exercise price, shares of our common stock having a value of twice the Right's exercise price.
- Pursuant to our Restated Certificate of Incorporation, our Board of Directors has the authority to issue preferred stock with voting or other rights or preferences that could impede the success of any attempt to effect a change in control or takeover of the Company.
- Our Restated Certificate of Incorporation provides that our Board of Directors will be divided into three classes of approximately equal numbers of directors, with the term of office of one class expiring each year over a three-year period. Classification of directors has the effect of making it more difficult for stockholders to change the composition of our Board. At least two annual meetings of stockholders, instead of one, will generally be required to effect a change in the majority of the Board.

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 significant 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.

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 777 E. Sonterra Blvd., Suite 350, San Antonio, Texas. These offices, consisting of approximately 20,300 square feet, are leased through March 2014 at $0.5 million per year.

All our oil and gas properties, reserves, and activities are located onshore in the continental United States. However, one parcel of the proposed Output acquisition is located offshore in shallow federal waters of the Gulf of Mexico. 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, 2006, 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 M. Cobb & Associates, Inc., both Dallas-based worldwide petroleum-consulting firms, made these estimates for 2006 and 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, 2006, 2005 and 2004 are set forth in Notes to the Audited Consolidated Financial Statements included in this Report.

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, 2006, Flint Hills 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, 2006, Houston Ship Channel spot market price of $5.40 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 our estimated oil and natural gas reserves.

Detail of PV-10 and Reconciliation to Standardized Measure

PV-10 Value of Estimated Future Net Revenues, by year:		*(in thousands)*
2007	$	14,933
2008		14,732
2009		11,265
2010		8,077
2011		6,364
Thereafter		37,333
Total PV-10 value		92,704
Plus present value of estimated income tax benefit		9,315
Standardized measure	$	102,019

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.

	2006		**2005**		**2004**	
Proved Oil & Gas Reserves at December 31,	**Volumes**	**Mix ***	**Volumes**	**Mix ***	**Volumes**	**Mix ***
Natural gas (Bcf)	8.0	19%	9.7	25%	17.7	47%
Oil (mmBbls)	5.6	81%	5.0	75%	3.4	53%
Natural gas equivalent (Bcfe) *	41.4	100%	39.4	100%	37.9	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,		
	2006	2005	2004
Oil:			
Sales volumes in Barrels (Bbl)	791,000	397,000	321,000
Average realized sales price per Bbl	$62.56	$54.21	$38.72
Gas:			
Sales volumes in mcf	1,104,000	2,222,000	2,975,000
Average realized sales price per mcf	$7.18	$7.65	$5.96
Equivalent Units: (1)			
Sales volumes:			
mcfe	5,852,000	4,605,000	4,901,000
BOE	975,000	767,000	817,000
Average cost per equivalent: (2)			
mcfe	$1.67	$1.88	$1.44
BOE	$10.05	$11.27	$8.64

(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
12/31/06	49,240	28,456	277	234.93	113	66.76	390	301.69
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

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, 2006, we owned, by lease or in fee, the following undeveloped acres:

United States	**Gross Acres**	**Net Acres**	**Estimated 2007 Delay Rentals**
			($ in thousands)
Texas ***(1)***	748,320	589,463	$ 849
North Dakota ***(2)***	80,124	79,980	3
South Dakota	2,637	1,635	1
Total	831,081	671,078	$ 853

(1) In February 2007, we entered into an agreement to acquire a company that owns additional acreage in the Midcontinent and Gulf Coast regions and shallow Gulf of Mexico waters. The transaction is expected to close on or about April 2, 2007.
(2) Most of our undeveloped leases in North Dakota will expire during 2007.

Thirteen Texas leases totaling approximately 390,256 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:

	2006		**2005**		**2004**	
Completions Summary:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Drilling Well Completions:						
Oil wells ***(1)***	37	33.47	24	17.76	24	21.43
Gas wells ***(1)***	1	1.00	4	2.00	22	11.60
Dry holes ***(2)***	2	1.62	-	-	-	-
Total Drilling Wells Completed	40	36.09	28	19.76	46	33.03
Re-entries Completed:						
Oil wells	6	5.45	1	1.00	3	1.30
Gas wells	-	-	2	2.00	3	2.98
Injection wells	1	1.00	-	-	-	-
Dry holes	2	1.13	-	-	-	-
Total Re-entries Completed ***(3)***	9	7.58	3	3.00	6	4.28
Wells Completed in Year	49	43.67	31	22.76	52	37.31

(1) The 2006 column includes three oil wells spud in prior years and completed in 2006, while the 2004 column includes one oil and one gas well spudded during 2003 and completed in 2004.
(2) The dry holes in the 2006 column were wells spud in prior years.
(3) Total re-entries begun but not completed by year were: 2006 -- 3, 2005 -- 2, 2004 -- 3.

		2006		2005		2004	
In-Progress Recap:		**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Beginning In-Progress ("BIP")		54	40.67	54	41.86	39	30.37
Add -	Wells recategorized to in-progress	-	-	3	2.59	-	-
	New re-entries begun not finished	2	1.50	1	0.50	3	1.80
	New wells spud not finished	11	9.50	14	10.11	16	12.19
Less -	Completions of BIP	5	4.00	-	-	4	2.50
	BIP wells transferred to others	-	-	18	14.39	-	-
	BIP wells to be plugged	3	2.25	-	-	-	-
Ending In-Progress		59	45.42	54	40.67	54	41.86

2006 Activity: We participated in 58 wells, including new drilling of 46 wells (41.47 net) and the re-entry of 12 (9.58 net) existing wells. We operated 36 (gross and net) of the newly drilled wells. Of the current-year drilling wells, 11 (9.50 net) remained in-progress at December 31, 2006. Six (5.45 net) of the re-entered wells were put on production as oil wells, one is being used as a water injection well, and two (1.13 net) are waiting to be plugged, while the remaining three (2.0 net) wells are in completion phase.

At December 31, 2006, in-progress wells included 11 development wells, two new developmental re-entries, and one new exploratory re-entry, all spudded in 2006, as well as 45 developmental wells that remained in progress from the beginning of 2006. Most of the in-progress wells are being scheduled for recompletion as horizontal wells or into other zones.

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 were pending completion at December 31, 2005. 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 remained in progress from the beginning of 2005.

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 coalbed methane 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.

GAS GATHERING SYSTEM

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. No significant additions were made to the gathering system in 2006 or 2005.

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.

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, to purchasers behind the Duke Three Rivers processing plant, or to a local distribution customer in Piedras Negras, Mexico. 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,		
	2006	**2005**	**2004**
Residue gas and NGL sales volumes (mmBtu)	1,878,000	3,082,000	4,062,000
Average sales price per mmBtu	$8.04	$9.08	$6.69

ITEM 3. LEGAL PROCEEDINGS

We were not involved in any matters of litigation as of March 13, 2007.

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 2006.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our Common Stock trades on the NASDAQ Global Select Market under the symbol "TXCO," having moved up from the NASDAQ Capital Market during 2006. The following table sets forth the high and low intra-day sales prices per share of our Common Stock for the periods indicated on the NASDAQ Global Select Market. The sales information below reflects inter-dealer prices, without retail mark-ups, mark-downs or commissions, and may not necessarily represent actual transactions.

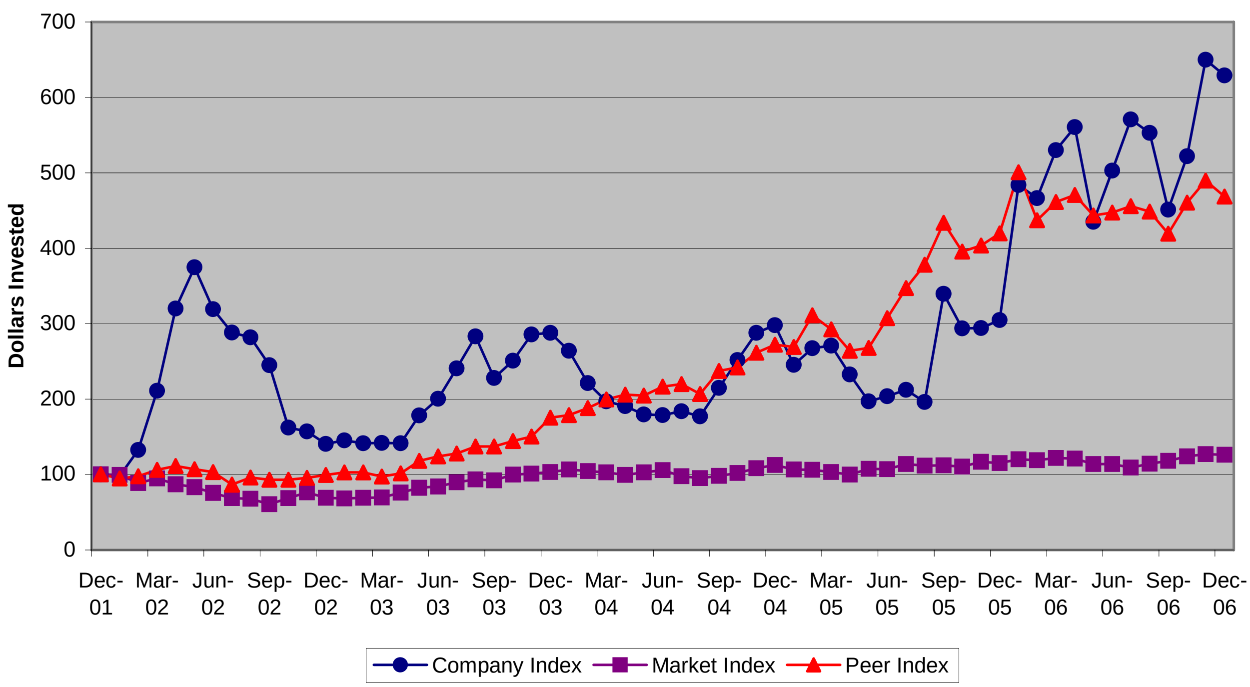
	Range of Bid Prices	
Quarter Ended:	**High**	**Low**
December 2006	$ 14.62	$ 8.76
September 2006	13.26	8.68
June 2006	12.77	8.84
March 2006	13.09	6.40
December 2005	$ 8.84	$ 5.37
September 2005	7.58	3.90
June 2005	5.98	3.93
March 2005	6.51	4.75

As of March 13, 2007, there were 1,117 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 stockholders.

Comparative Performance Graph: The following graph compares the performance of the Company's common stock for the five-year period commencing December 31, 2001 to (i) the NASDAQ market composite index ("NASDAQ-US") and (ii) NASDAQ exploration and production companies comprised of approximately 30 active companies which trade on either the NASDAQ National Market System or the NASDAQ Small-Cap Market. The graph assumes that a $100 investment was made in the Company's common stock and each index on December 31, 2001, and that all dividends were reinvested. Also included are the respective investment returns based upon the stock and index values as of the end of each year during such five-year period. The information was provided by the Center for Research in Security Prices ("CRSP") of The University of Chicago Graduate School of Business. The index of exploration and production companies used includes all available NASDAQ stocks under SIC codes 1310-19 (companies engaged in oil and gas exploration and production operations) actively traded on NASDAQ during the comparative term. The list of comparative companies is available to shareholders directly from CRSP or may be obtained at no cost by contacting the Company and requesting the information.

Date	Company Index	Market Index	Peer Index
12/31/2002	140.6	69.1	99.3
12/31/2003	287.7	103.4	175.4
12/31/2004	298.1	112.5	272.2
12/30/2005	304.7	114.9	420.0
12/29/2006	629.2	126.2	468.5

Comparison of Five Year Cumulative Total Return



The foregoing performance graph is being furnished as part of this Report solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish our stockholders with such information and, therefore, is not deemed to be filed, or incorporated by reference into any filing, by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934.

The following table reflects balances on our equity compensation plans at December 31, 2006:

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	956	$2.90	1,052
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	956	$2.90	1,052

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 Report commencing on page F-1.

	Years Ended December 31				
(In thousands, except earnings per share data)	**2006**	**2005**	**2004**	**2003**	**2002**
Operating revenues	$ 72,418	$ 67,000	$ 57,735	$ 39,545	$ 18,958
Net income (loss)	7,241	13,741	2,797	41	(311)
Earnings (loss) per common share:					
Basic	0.23	0.48	0.11	0.00	(0.02)
Diluted	0.22	0.48	0.10	0.00	(0.02)
Cash dividends	n/a	n/a	n/a	n/a	n/a
Net cash provided by operating activities	24,724	6,260	16,447	15,158	7,389
Net cash provided (used) by investing activities	(59,845)	28,293	(39,718)	(36,282)	(27,655)
Net cash provided (used) by financing activities	32,920	(31,588)	20,208	24,971	20,580
Total assets	143,801	109,536	114,237	84,206	53,036
Long-term obligations	4,054	2,027	31,654	28,909	7,217
Stockholders' equity	$ 123,652	$ 83,281	$ 65,682	$ 42,792	$ 36,970
Weighted average shares outstanding:					
Basic	31,916	28,444	26,066	20,781	19,081
Diluted	33,247	28,885	26,971	21,295	19,081

n/a - No cash dividends have been paid.

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 ("MD&A"). This discussion should be read in conjunction with our Financial Statements and Notes thereto, beginning on page F-1 of this Report.

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 stockholder 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 Global Select Market℠ under the symbol "TXCO."

We currently have five drilling rigs operating on our extensive 650,000-acre position in the Maverick Basin. Completions in 2006 included 43 oil and one gas wells, which included six re-entries, while 14 wells spud during the year remained in progress at year-end. The 2007 capital expenditures budget includes funds for more than 90 wells (48 in the Glen Rose, 21 in the San Miguel Oil Sands, 11 in the Pena Creek San Miguel, five in the Georgetown, three in the Pearsall and one in the Marfa Basin), 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 2006. (For further discussion of this activity, see Item 1 Business, "Principal Areas of Activity" and "Drilling Activity"). 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 a 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 $7.2 million, or $0.23 per basic share and $0.22 per diluted share, for the year ended December 31, 2006, compared to net income of $13.7 million, or $0.48 per basic and diluted share, for the prior year. Net income for 2005 included a $24.5 million pre-tax gain on sale of selected interests in the Maverick Basin to EnCana Oil & Gas (USA) Inc. Higher oil and gas sales revenues were largely offset by lower gas gathering revenues. Lower gas gathering operation expenses, net losses on derivatives and interest expense were partially offset by increases in lease operating expenses, depreciation, depletion and amortization, and general and administrative expenses. These factors are discussed in the Results of Operations section.

We continued our ongoing trend of annual reserve growth in 2006 by recording net proved reserve additions of 2.0 Bcfe. Combined with annual production of 5.9 Bcfe, our gross reserve additions for the year were 7.9 Bcfe. Estimated year-end proved oil and gas reserves were 41.4 Bcfe, 5.1% above the 39.4 Bcfe at year-end 2005. We achieved a 134.8% all-source reserve replacement rate in 2006. Positive cash flow provided from operations totaled $24.7 million, a 295.0% increase from the prior year primarily due to higher operating income for 2006 and payments in 2005 for the termination of hedges of natural gas. The following table illustrates key features of our continuous development over the four fiscal years presented.

	Year Ended December 31,			
Development:	**2006**	**2005**	**2004**	**2003**
No. of oil wells completed	43	25	27	37
No. of gas wells completed	1	6	25	19
Gas sales (mmcf)	1,104	2,222	2,975	2,108
Gas reserve additions from drilling (mmcf)	198	5	6,432	5,037
Oil sales (mBbl)	791	397	321	454
Oil reserves additions from drilling (mBbl)	778	522	1,396	1,115
Gas equivalent sales (Bcfe)	5.9	4.6	4.9	4.8
Oil equivalent sales (mBOE)	975	768	817	805
Reserve additions (Bcfe)				
Drilling	4.9	3.2	14.8	11.7
Revisions of previous estimates	3.0	4.3	(0.9)	(2.7)
Purchased in place	-	-	0.5	0.7
Total reserves added (Bcfe) ***(1)***	7.9	7.5	14.4	9.7

Development -- continued:	Year Ended December 31, 2006	2005	2004	2003
Reserve replacement rate ***(2)***				
Drill bit	135%	161%	283%	186%
Drill bit plus purchases (all sources)	135%	161%	295%	200%
Non-developed Texas acreage leased ***(3)***	748,320	758,031	491,289	479,761
Non-developed Williston Basin acreage leased ***(4)***	82,761	83,721	84,654	91,804

(1) Make-up of total proved developed reserves at year-end 2006: 32% gas, 68% oil.
(2) 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.
(3) Subsequent to year end 2006, we signed agreements to acquire an additional 61,513 gross (52,880 net) undeveloped acres.
(4) Most of our undeveloped leases in North Dakota will expire during 2007.

2006 Sale of Partial Interest: In April 2006, we sold a 50% WI in 140,000 gross acres in the Marfa Basin. The cash proceeds from this sale were used in our capital expenditures program. The Marfa Basin is located in West Texas, along the Ouachita Thrust, and is prospective for natural gas from the Barnett and Woodford shales.

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. See Note M to our Consolidated Financial Statements for information regarding the accounting for this transaction.

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 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 of 2005. Proceeds from the transaction were used to redeem our outstanding Preferred Stock for $16 million and pay down $32 million on our 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.

Proposed Acquisition: On February 20, 2007, we signed a merger agreement to purchase Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase is $91.6 million in cash, subject to certain adjustments, and $4.0 million of TXCO common stock. The transaction, the largest in TXCO's history, will double our proved reserves and increase current oil and gas production by nearly two thirds. The core of the Output holdings is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk and Eagleford/Woodbine formations. Other Output holdings to be acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf Coast waters. Closing is expected on or about April 2, 2007.

Separately in February 2007, we acquired an interest in primarily shallow horizons under 85,681 acres in an agreement with EnCana, expanding our Maverick Basin interests to nearly 630,000 net acres.

***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 2065. However, as shown in the table in Item 2 of this Form 10-K, we expect to realize approximately 38.5% of that production by year-end 2011.

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 our bank 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 our bank 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"). The Facility was entered into in 2004 and expires in June 2008. However, as discussed below under "New Credit Facility," we expect to replace the Facility with new credit facilities in connection with the closing of the Output Exploration LLC acquisition in April 2007.

The 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, 2006, the borrowing base, inclusive of tranche A and tranche B, stood at $32.0 million. The unused borrowing base at March 1, 2007, was $13.3 million, with $18.7 million outstanding at an average interest rate of 8.25%. 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 corporate borrowers. 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, restrictions on the payment of dividends, and prohibitions against change in control or 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, 2006, we were in compliance with all covenants under the Facility.

New Revolving Credit Facility

Subsequent to year-end and in connection with the proposed acquisition of Output Exploration LLC, we signed a commitment letter with BMO Capital Markets Corp. and the Bank of Montreal to enter into a new, four-year senior secured revolving credit facility and a new, five-year secured second-lien term loan facility (the "New Facilities") to fully finance the acquisition, as well as refinance the existing Facility and provide additional working capital. The New Facilities will be administered by Bank of Montreal, are collateralized by all of our proven oil and gas properties and contain terms and conditions consistent with similarly positioned companies. The aggregate notional principal amounts are $125.0 million and $80.0 million for the senior revolving credit facility and senior second lien, respectively. TXCO has paid a $100,000 acceptance fee and will be responsible to pay an arrangement fee of approximately $1.9 million upon initial funding of the New Facilities at the closing date of the acquisition. Upon closing, the New Facilities will replace the existing Facility with Guaranty Bank.

2007 Capital Requirements Outlook

Overall: We believe our bank credit facilities, 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 2007. 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 our bank credit facilities. 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.

Our board of directors has approved a 2007 capital budget in a range of $70 million to $75 million -- our largest ever, targeting more than 90 gross wells, as well as certain leasehold acquisitions. We expect to fund our CAPEX program from internal cash flow and our credit facilities. We expect the CAPEX program to grow after the closing of the proposed Output Exploration LLC acquisition.

Our capital budget may be revised, based on drilling plan changes by partners, rig availability, drilling results, operational developments, unanticipated transaction opportunities, market conditions or commodity price fluctuations. 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 2007 wells:

	Typical Gross Well Costs	
(In thousands)	**Dry Hole**	**Completed**
Glen Rose oil porosity zone horizontal well	$ 1,000	$ 1,300
Glen Rose shoal horizontal gas well	1,000	1,500
Glen Rose vertical well	450	650
Georgetown horizontal oil well	550	925
Pearsall/Sligo gas well	3,000	3,500
San Miguel waterflood oil well	150	335
San Miguel oil sands heavy oil well	300	350

***Maverick Basin Activity*:** The Glen Rose Porosity oil play (50-100 percent WI) will continue to receive the largest share of our CAPEX budget, $36.0 million for 36 wells, including six re-entries. The emerging San Miguel oil sands play (50% WI) will receive $3.7 million for 21 wells. The budget calls for three wells to the gas-prone Pearsall formation (50% WI), budgeted at $4.8 million. The budget allocates $3.0 million for five wells targeting the Georgetown formation (63-100% WI) and $7.6 million for 12 wells to the Glen Rose reefs and shoals. We will continue development of our Pena Creek San Miguel waterflood (100% WI) with $3.5 million set aside for 11 wells.

Marfa Basin Activity: In the Marfa Basin (50% WI), which is prospective for the Barnett and Woodford shales, the Company has allocated approximately $3.0 million for a three-dimensional seismic acquisition program or one new horizontal well.

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 2007 delay rentals of $3,600. 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 2006 and have participated in one well (4.2% WI) in the Red River "B" subsequent to year-end 2006. No additional funds are included in our 2007 CAPEX budget for this area. Most of our undeveloped leases in North Dakota will expire during 2007.

Proposed Acquisition: On February 20, 2007, we signed a merger agreement to purchase Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase is $91.6 million in cash, subject to certain adjustments, and $4.0 million of TXCO common stock. Capital expenditures are expected to be approximately $15 million in 2007 for the Output properties.

Sources and Uses of Cash

Net cash provided by operating activities fluctuated over the three-year period presented from a low of $6.3 million in 2005 to a high of $24.7 million in 2006. The low point in 2005 was largely due to a one-time cash outlay in excess of $9.9 million for the termination of derivative contracts in October of that year. The impact of current federal income taxes became significant in 2005 due to the large gain recognized on the 2005 Asset Sale. The following table illustrates the impact of the items to cash provided by operations and how, on an adjusted basis, the respective periods compare. We use the "adjusted cash provided by operating activities" measure in our internal analysis and review of our operational performance. We believe that this non-GAAP measure provides investors with useful information in comparing our performance over different periods, particularly when comparing one of these periods to a period in which we did not incur costs for termination of derivative contracts. By using this non-GAAP measure we believe investors get a better picture of the performance of our underlying business. However, investors should consider this adjusted non-GAAP measure in addition to, not as a substitute for or as superior to, financial reporting measures prepared in accordance with GAAP

Adjusted Cash Provided by Operating Activities
For the Years Ended December 31,

(In thousands)	**2006**	**2005**	**2004**
Net cash provided by operating activities	$ 24,724	$ 6,260	$ 16,447
Adjustments:			
Payment to terminate derivative treated as an investment	-	7,564	-
Payment to terminate cash flow hedge	-	2,356	-
Federal income tax, current & deferred	2,661	3,923	146
Adjusted cash provided by operating activities	$ 27,385	$ 20,103	$ 16,593
Change from prior year	+7,282	+3,510	+1,385
% Change from prior year	+36.2	+21.2%	+9.1

The following tables set forth the Company's cash sources, and uses of cash, during the three years presented. "Adjusted cash provided" and "cash utilized" are non-GAAP measures. We believe that the presentation of non-GAAP financial measures in the form of "adjusted cash provided" and "cash utilized" provides important supplemental information to management and investors regarding the sources of liquidity and uses of cash by the Company during the fiscal period. Our management uses these non-GAAP financial measures when evaluating the Company's liquidity and funds available for future development. The Company has chosen to provide this information to investors so they can analyze the Company's liquidity and financial condition in the same way that management does and use this information in their assessment of the valuation of the Company. However, investors should consider these measures in addition to, not as a substitute for or as superior to, financial reporting measures prepared in accordance with GAAP.

Total adjusted cash provided from all sources, listed in the following table, includes funds from private placements of the Company's common stock in 2006 and 2004 and from the 2005 Asset Sale, which caused a spike in the total for 2005.

Adjusted Cash Provided
For the Years Ended December 31,

(In thousands)	**2006**	**2005**	**2004**
Beginning cash reserves	$ 6,083	$ 3,118	$ 6,181
Net cash provided by operating activities	24,724	6,260	16,447
Internally generated funds	30,807	9,378	22,628
Proceeds from sale of assets	23	78,002	-
Issuance of common stock, net of expenses	30,565	2,915	18,620
Proceeds from bank credit facility	13,450	15,001	19,099
Proceeds from installment obligations	494	356	377
Total other sources of cash	44,532	96,274	38,096
Adjusted Cash Provided, from all sources	$ 75,339	$ 105,652	$ 60,724
Change from prior year	-30,313	+44,928	+11,845
% Change from prior year	-28.7%	+74.0%	+24.2

We applied these funds as indicated in the following table:

Uses of Cash
For the Years Ended December 31,

(In thousands)	**2006**	**2005**	**2004**
Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$ 52,927	$ 49,672	$ 39,335
Other property and equipment	6,941	37	224
Net distributions to minority interests	-	-	159
Sub-total	59,868	49,709	39,718
Debt principal payments, excluding interest	11,589	33,860	17,888
Redemption of preferred stock	-	16,000	-
Cash Utilized	$ 71,457	$ 99,569	$ 57,606

Proceeds from the 2005 Asset Sale were used to redeem the preferred stock and repay essentially all debt, causing an increase in cash utilized for that year. Additionally, interest payments of $0.2 million, $3.2 million and $3.0 million were paid in the years ended December 31, 2006, 2005 and 2004, respectively.

Working Capital and Current Ratio Calculations
For the Years Ended December 31,

(In thousands, except ratios)	**2006**	**2005**	**2004**
Current assets	$ 18,369	$ 17,047	$ 13,038
Less: Current liabilities	16,095	24,228	18,567
Net working capital	$ 2,274	$ (7,181)	$ (5,529)
Current ratio	1.14	0.70	0.70

2006 Sale of Partial Interest: In April 2006, we sold a 50% WI in 140,000 gross acres in the Marfa Basin. The cash proceeds from this sale were used in our capital expenditures program. The Marfa Basin is located in West Texas, along the Ouachita Thrust, and is prospective for natural gas from the Barnett and Woodford shales.

2005 Asset Sale: Please see the discussion regarding this transaction in the Overview section of this MD&A.

2005 Acquisitions: In October 2005, we acquired a 100% WI in 140,000 gross acres in the Marfa Basin. We paid for this acquisition with a combination of stock and cash.

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. See Note M to our Consolidated Financial Statements for information regarding the accounting for this transaction.

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 2005, and later amended, gave us a 75% interest in 12,200 acres and included a 3-D seismic survey of the area. In June 2005, we acquired a 75% WI in seismic option agreements on approximately 62, 000 gross acres adjacent to our Burr and Wipff leases. In October 2005, 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.

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 in our Audited Consolidated Financial Statements and the Sales Volumes discussion.

Percentage Change in Selected Income Statement Items:	**2006 vs. 2005**	**2005 vs. 2004**	**2004 vs. 2003**
Oil and gas revenues	+46.7	+27.7	+23.7
Gas gathering revenues	-44.2	+3.2	+81.8
Gas gathering expenses	-42.6	+11.9	+67.1
Lease operations expense	+12.0	+18.5	+23.9
Impairment & abandonments	+22.4	-40.3	-6.7
Depreciation, depletion & amortization	+89.3	+27.9	+14.2
Net income (loss)	-47.3	+391.3	+6,742.1
Basic income (loss) per common share	-52.1	+336.4	+100.0

Percentage Change in Selected Operating Items:	**2006 vs. 2005**	**2005 vs. 2004**	**2004 vs. 2003**
Oil sales volumes	+99.2	+23.6	-29.2
Gas sales volumes	-50.3	-25.3	+41.1
Combined sales volumes	+27.1	-6.1	+1.5
Net residue and NGL sales volumes	-39.1	-24.1	+38.8
Oil average sales price per Bbl, excluding hedging impact	+15.4	+40.0	+36.8
Gas average sales price per mcf, excluding hedging impact	-6.2	+28.3	+8.9
Residue & NGL sales price per mmBtu	-11.5	+35.7	+33.5

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

Gas Gathering Results: *($ in thousands)*	2006	2005	2004
Revenues:			
Residue gas sales	$ 13,039	$ 23,330	$ 20,967
Natural gas liquids sales	2,053	4,652	6,205
Transportation and other revenue	761	448	364
Total gas gathering revenues	15,853	28,430	27,536
Expense:			
Third-party gas purchases	15,223	27,112	23,937
Transportation and marketing expenses	89	278	498
Direct operating costs	943	922	857
Total gas gathering operations expense	16,255	28,312	25,292
Gross margin	$ (402)	$ 118	$ 2,244

2006 Compared to 2005

Revenues

Total revenues increased by $5.4 million. Oil sales volumes increased by 394,146 BO and natural gas sales volumes decreased by 1.1 Bcf, resulting in a combined increase of 1.2 Bcfe or 207,827 BOE. Average daily net oil production rates were 2,168 Bbls, a 99.2% increase. The increase in 2006 oil sales volumes reflects increased drilling in the Glen Rose porosity play, as well as the increase in our interests on most Glen Rose wells drilled. Average daily net gas sales were 3.0 mmcf, a 50.3% decrease. The decrease in natural gas sales volumes primarily resulted from only one new gas well being placed on production during 2006 and the sale of interests in certain Georgetown wells as part of the 2005 Asset Sale, as well as normal declines experienced in maturing gas wells.

Excluding the impact of cash flow hedges: On an equivalent-unit basis, sales prices averaged 17.3% higher. Crude oil prices averaged 15.4% higher while natural gas prices were down 6.2%. Higher average realized commodity prices had a $6.1 million positive impact on revenues. Commodity prices have been, and continue to be, volatile. During 2006, realized gas prices ranged from a high of $9.15 per mcf in January to a low of $3.71 per mcf in October, while realized crude oil prices ranged from a high of $70.48 in July to a low of $55.99 in December.

Oil and gas revenues decreased $0.9 million during the fourth quarter of 2006 as the result of cash flow hedges. There was no comparable impact on revenues in 2005. Of this total, $0.1 million related to settlements on oil hedges, while $0.8 million reflects the accretion of deferred losses related to gas hedges that were terminated in 2005. We will expense the remaining $1.4 million related to the terminated gas hedges over the first four months of 2007.

Lease Operations

Lease operating expense increased $0.8 million to $7.2 million. This increase is primarily due to the addition of 43 new oil wells and one new gas well during 2006. 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 decreased $0.21 to $1.67, primarily due to our focus this year on the Glen Rose porosity play in which we experience lower lifting costs per barrel.

Gas Gathering

Gas gathering revenues decreased by $12.6 million and related operating expenses decreased by $12.1 million. These decreases are consistent with the lower average commodity prices and decreased gas throughput for the gathering system compared to the prior period. See the "Gas Gathering Results" table above. In April of 2006, EnCana elected to market its gas, rather than sell to us. EnCana continues to use our pipeline to transport its gas to market.

Impairment

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 increased by 22.4% primarily due to higher impairment rates used.

Depreciation, Depletion and Amortization ("DD&A")

DD&A increased by $11.2 million, or 89.3%, reflecting the number of newly drilled producing wells being depleted and our focus on drilling Glen Rose porosity wells which are depleted at a rapid rate. More particularly there were six Glen Rose porosity wells drilled in the third and fourth quarters that depleted very rapidly, hence the significant increase in depletion for the quarter. These wells are being evaluated as re-completion candidates. The increase in depreciation was due to increased investments in other equipment including computer, pipeline and well service equipment additions.

General and Administrative ("G&A")

($ in thousands)	**2006**	**2005**		**% change**
Non-cash, stock compensation expense	$1,207	$ -	+	n/m
Other G&A expense	6,091	5,439	+	12.0
Total G&A expense	$7,298	$5,439	+	34.2

n/m - not meaningful since prior year was zero

G&A costs represent 10.1% of revenues, up from 8.1% of revenues for 2005. The increase was primarily due to recording non-cash stock compensation expense related to restricted stock grants during first-quarter 2006, and unvested stock options that are now required to be expensed by SFAS No. 123R. No comparable expenses were recorded during 2005.

The increase also reflects higher salaries, benefits, and office-related expenses for a full year related to two employees hired across the organization during 2005, along with a partial year for seven new corporate employees hired during 2006.

During 2006, we spent $23,000 for internal audit services along with $43,837 attributable to the continued documentation and testing of our internal controls resulting from the requirements of the Sarbanes-Oxley Act. Comparable expenditures in 2005 were $-0- and $48,487, respectively.

Derivative Gain / Loss

Net losses on derivatives were $0.7 million representing a decline of $10.5 million. This was a result of expiring derivatives treated as investments, as well as, moderation of crude oil prices.

Interest Income / Expense

The increase in interest income reflects higher average cash levels in interest-bearing accounts at higher average interest rates. Interest expense declined $2.7 million due to low average debt levels. Both were positively impacted by the 2005 Asset Sale. Proceeds from that sale essentially eliminated our then-outstanding debt.

Loss / Gain on Sale of Assets

The prior year results reflect the $24.5 million pre-tax gain on the 2005 Asset Sale. No comparable gain was recognized during 2006.

Net Income & Earnings Per Share

We reported a net income of $7,241 million, $0.23 per basic share and $0.22 per diluted share, for the year ended December 31, 2006, compared to a net income of $13.7 million, $0.48 per basic and diluted share for the prior year.

2005 Compared to 2004

Revenues

Total revenues increased by $9.3 million. Natural gas sales volumes decreased by 753 mmcf while oil sales volumes increased by 75,911 BO, 455 mmcfe. Average daily net gas sales were 6.1 mmcf, a 25.0% decrease. 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. Average daily net oil production rates were 1,088 Bbls, a 24.0% increase. The increase in oil sales volumes reflected the increase in our interests on most Glen Rose wells drilled following the 2005 Asset Sale, 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. Crude oil prices averaged 40.0% higher while natural gas prices were up 28.3%. Average higher prices 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.

Lease Operations

Lease operating expense increased $1.0 million, or 18.5%. This increase was 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 to $1.88. Typically, waterfloods incur higher costs of operations. Excluding the Pena Creek field, operating expense per mcfe for 2005 was $1.57, an increase of $0.35. 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 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 $1.52 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.

Gas Gathering

Gas gathering revenues increased 3.2%, while related operating expenses increased 11.9%. 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 "Gas Gathering Results" table in the "2006 Compared to 2005" section.

Impairment

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

DD&A increased by $2.7 million, or 27.9%, 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.

General and Administrative

While G&A costs increased 12.1%, they declined to 8.1% of revenues. This compares favorably to 2004 when G&A 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 G&A costs were consistent with the expanded compliance burden mandated by the adoption of the Sarbanes-Oxley Act in mid-2002.

Derivative Gain / Loss

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.

Interest Income / Expense

The 178.1% increase in interest income reflects higher average cash levels in interest-bearing accounts, while interest expense was essentially flat in 2005 as compared to 2004 due to higher average debt levels in the first nine months of 2005. Both were favorably impacted by the 2005 Asset Sale. Proceeds from that sale essentially eliminated our then-outstanding debt.

Loss / Gain on Sale of Assets

The results reflect the $24.5 million pre-tax gain on the 2005 Asset Sale. No comparable gain was recognized during 2004.

Net Income & Earnings Per Share

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

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES AND COMMITMENTS

The following is a summary of our future payments on obligations as of December 31, 2006.

	Payments Due by Period *(in thousands)*				
Contractual Obligations	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**	**Total**
Long-term debt (1)	$ -	$ 2,351	$ -	$ -	$ 2,351
Operating lease obligations	507	1,177	1,089	1,128	3,901
Notes payable	267	-	-	-	267
Total Contractual Cash Obligations	$ 774	$ 3,528	$ 1,089	$ 1,128	$ 6,519

(1) excluding interest

See the discussion in the overview section of the acquisition and new credit facility entered into subsequent to year end 2006.

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.

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 drilling 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.

Revenue Recognition

We recognize oil and gas revenue from our 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.

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. During fourth quarter 2006, we transferred our leasehold interests to TXCO Energy Corp. ("TEC"), a wholly-owned subsidiary. For tax purposes, TEC elected to expense intangible drilling costs as they are incurred.

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, 2006.

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 June 2006, the Financial Accounting Standards Board ("FASB") ratified the consensus on Emerging Issues Task Force ("EITF") Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement." The scope of EITF 06-3 includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, Universal Service Fund contributions and some excise taxes. The Task Force affirmed its conclusion that entities should present these taxes in the income statement on either a gross or a net basis, based on their accounting policy, which should be disclosed pursuant to APB Opinion No. 22, "Disclosure of Accounting Policies." If such taxes are significant and are presented on a gross basis, the amounts of those taxes should be disclosed. The consensus on EITF 06-3 will be effective for interim and annual reporting periods beginning after December 15, 2006. The adoption of the standard, effective January 1, 2007, is not expected to have a significant impact on our consolidated financial position, results of operations or liquidity.

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109", ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. The adoption of the standard, effective January 1, 2007, is not expected to have a significant impact on our consolidated financial position, results of operations or liquidity.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements, however, for some entities, the application of SFAS No. 157 will change current practice. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. Management is currently evaluating the effect of these provisions on our results of operations, financial condition and liquidity.

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 2005 through 2006. In March and June 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 March 2005 derivatives expired in October 2006. 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 $5.7 million impact on our annual revenues based on 2006 sales volumes.

Derivative Contracts at Year End:

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

(1) The fair value of our outstanding derivatives 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.

The Consolidated Balance Sheet at December 31, 2006, includes a total liability for derivative mark-to-market losses of $0.3 million as "Accrued derivative obligation - current," as well as a $0.1 million liability for "Derivative settlements payable" both in the "Current Liabilities" section. A derivative mark-to-market gain of $2.0 million was recognized on the Consolidated Statement of Operations in 2006. At the end of February 2007, the valuation of the remaining hedges is an unrealized liability of approximately $0.2 million.

Interest Rate Risk**:** We have borrowed funds under our Credit Facility with Guaranty Bank, with interest based on LIBOR rates plus an applicable margin. At March 1, 2007, we had $18.7 million in total borrowings under the Facility, with an average interest rate of 8.25%. At our current borrowing level, an annualized 10% fluctuation in interest charged on the floating rate balance at March 1, 2007, would have $0.2 million 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.

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 under the supervision and with the participation of 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 such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this 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 to provide reasonable assurance that the information required to be disclosed in our Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified by the SEC, and that information is communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. During the fourth quarter of 2006, there were no changes in the Company's internal controls or in other factors that materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. 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, 2006. 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, 2006, 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, 2006, is presented on the next page.

Attestation 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 (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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 of Delaware, Inc. maintained effective internal control over financial reporting as of December 31, 2006, 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, 2006, 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, 2006 and 2005 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006, of The Exploration Company of Delaware, Inc. and our report dated March 9, 2007, expressed an unqualified opinion thereon.

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

San Antonio, Texas
March 9, 2007

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 2007 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, 2006.

In October 2006, we amended our "Code of Conduct for All Employees and Directors." This document was filed with the SEC as Exhibit 14.1 with its Form 8-K on October 31, 2006, 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 for the 2007 Annual Meeting of stockholders under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2007 Annual Meeting of stockholders under the heading "Certain Relationships and Related Transactions.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this section will be contained in the Proxy Statement for the 2007 Annual Meeting of stockholders under the heading "Auditor Independence" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND 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, 2006 and December 31, 2005.

Consolidated Statements of Operations, Years Ended December 31, 2006, 2005 and 2004.

Consolidated Statements of Stockholders' Equity, Years Ended December 31, 2006, 2005 and 2004.

Consolidated Statements of Cash Flows, Years Ended December 31, 2006, 2005 and 2004.

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.		10-K	3.1	03/16/2006
3.2	Amended and Restated Bylaws of The Exploration Company of Delaware, Inc.		S-8	3.1	05/10/2002
4.1	Credit Agreement between the Registrant and Guaranty Bank, FSB, dated June 30, 2004.		10-Q	4	08/09/2004
4.2	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
4.3	Waiver and Second Amendment to Credit Agreement, effective August 23, 2005.		10-Q	4.1	11/09/2005
4.4	Third Amendment to Credit Agreement between the Registrant and Guaranty Bank, FSB as Lender, Effective as of December 15, 2005.		10-K	3.1	03/16/2006
4.5	Fourth Amendment to Credit Agreement between the Registrant, TXCO Energy Corp. and Guaranty Bank, FSB as Lender, Effective as of November 1, 2006.	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.		10-K	10.21	03/15/2004
10.7*	Sample of Amended and Restated Change of Control Letter Agreements issued to all employees during December 2004.		8-K	10.1	12/17/2004
10.8*	2005 Stock Incentive Plan		Def 14A	Appendix A	04/15/2005
10.9	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
10.10	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
10.11	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
10.12	Assignment - Comanche Ranch between the Registrant and CMR Energy, L. P. effective September 1, 2005.		10-Q	10.4	11/09/2005
10.13	Assignment - Glen Rose Rights between the Registrant and CMR Energy, L. P. effective September 1, 2005.		10-Q	10.5	11/09/2005

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
10.14	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
10.15	Seismic Data License Agreement between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.7	11/09/2005
10.16	Transition Services Agreement between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.8	11/09/2005
10.17	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
10.18	Operating Agreement between the Registrant and EnCana Oil & Gas (USA) Inc. effective September 1, 2005.		10-Q	10.10	11/09/2005
10.19	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
10.20*	Sample of Restricted Stock Award issued to all employees during the first quarter of 2006.		10-Q	10.2	05/10/2006
10.21	Purchase Agreement between the Registrant and several investors, dated March 30, 2006.		8-K	10.1	04/05/2006
10.22	Registration Rights Agreement between the Registrant and several investors, dated April 4, 2006.		8-K	10.1	04/05/2006
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
10.26*	Compensation arrangements for directors and named executives for 2007.		8-K		12/12/2006
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.		8-K	14.1	10/31/2006
21	Subsidiaries of the Registrant at December 31, 2006	X			
23.1	Consent of Akin, Doherty, Klein & Feuge, P.C.	X			
23.2	Consent of DeGolyer and MacNaughton	X			
23.3	Consent of Cobb & Associates	X			
31.1	Certification of Chief Executive Officer required pursuant to Rule 13a-14(a) and 15d-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) and 15d-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, 2007

By: /s/ James E. Sigmon
James E. Sigmon, President and Chairman of the Board

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/ James E. Sigmon James E. Sigmon	President and Chairman of the Board (Principal Executive Officer)	March 16, 2007
/s/ Michael J. Pint Michael J. Pint	Director	March 16, 2007
/s/ Robert L. Foree, Jr. Robert L. Foree, Jr.	Director	March 16, 2007
/s/ Alan L. Edgar Alan L. Edgar	Director	March 16, 2007
/s/ Dennis B. Fitzpatrick Dennis B. Fitzpatrick	Director	March 16, 2007
/s/ Jon Michael Muckleroy J. Michael Muckleroy	Director	March 16, 2007
/s/ P. Mark Stark P. Mark Stark	Chief Financial Officer Vice-President-Finance (Principal Financial and Accounting Officer)	March 16, 2007

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 (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Exploration Company of Delaware, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and cash flows for each of the three years in the period ended December 31, 2006, in conformity with U. S. generally accepted accounting principles.

As discussed in Note A to the consolidated financial statements, in 2006 the Company changed its method of accounting for share-based compensation.

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 of Delaware, Inc.'s internal control over financial reporting as of December 31, 2006 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 9, 2007 expressed an unqualified opinion thereon.

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

San Antonio, Texas
March 9, 2007

THE EXPLORATION COMPANY
Consolidated Balance Sheets

(in thousands)	December 31 2006	2005
Assets		
Current Assets		
Cash and equivalents	**$ 3,882**	$ 6,083
Accounts receivable:		
Joint interest owners	**3,321**	2,834
Oil and gas sales	**5,811**	6,510
Federal income tax	**4,468**	-
Prepaid expenses and other	**887**	1,620
Total Current Assets	**18,369**	17,047
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	**119,574**	84,467
Other Assets		
Deferred tax asset	**5,310**	7,242
Other assets	**548**	780
Total Other Assets	**5,858**	8,022
Total Assets	**$ 143,801**	$ 109,536

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Balance Sheets

(in thousands)	December 31 2006	2005
Liabilities And Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	**$ 7,969**	$ 10,003
Undistributed revenue	**1,035**	2,479
Current income taxes payable	**-**	4,952
Notes payable	**267**	262
Derivative settlements payable	**70**	151
Accrued derivative obligation - short-term	**321**	2,084
Other payables and accrued liabilities	**6,433**	4,297
Total Current Liabilities	**16,095**	24,228
Long-Term Liabilities		
Long-term debt	**2,351**	1
Accrued derivative obligation - long-term	**-**	461
Asset retirement obligation	**1,703**	1,565
Total Long-Term Liabilities	**4,054**	2,027
Commitments and Contingencies	**-**	-
Stockholders' Equity		
Preferred stock; authorized 10,000,000 shares,		
Series A, -0- shares issued and outstanding		
Series B, -0- shares issued and outstanding	**-**	-
Common stock, par value $0.01 per share; authorized		
50,000,000 shares, issued 33,290,698 and 29,479,697 shares, and outstanding 33,190,898 and 29,379,897	**333**	295
Additional paid-in capital	**122,108**	89,680
Retained earnings (accumulated deficit)	**2,619**	(4,622)
Accumulated other comprehensive loss, net of tax	**(1,162)**	(1,826)
Less treasury stock, at cost, 99,800 shares	**(246)**	(246)
Total Stockholders' Equity	**123,652**	83,281
Total Liabilities and Stockholders' Equity	**$ 143,801**	$ 109,536

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 2006	2005	2004
Revenues			
Oil and gas sales	**$ 56,520**	$ 38,533	$ 30,181
Gas gathering operations	**15,853**	28,430	27,536
Other operating income	**45**	37	18
Total Revenues	**72,418**	67,000	57,735
Costs and Expenses			
Lease operations	**7,248**	6,470	5,460
Production taxes	**2,551**	2,180	1,588
Exploration expenses	**2,968**	3,266	2,449
Impairment and abandonments	**1,722**	1,406	2,355
Gas gathering operations	**16,255**	28,312	25,292
Depreciation, depletion and amortization	**23,840**	12,597	9,851
General and administrative	**7,298**	5,439	4,853
Total Costs and Expenses	**61,882**	59,670	51,848
Income from Operations	**10,536**	7,330	5,887
Other Income (Expense)			
Interest income	**550**	89	32
Interest expense	**(269)**	(2,920)	(2,909)
Loan fee amortization	**(216)**	(132)	(83)
Derivative mark-to-market gain (loss)	**1,995**	(2,128)	(19)
Derivative settlements loss	**(2,686)**	(9,115)	-
(Loss) gain on sale of assets	**(8)**	24,540	-
Total Other Income (Expense)	**(634)**	10,334	(2,979)
Income before income taxes and minority interest	**9,902**	17,664	2,908
Minority interest in income of subsidiaries	**-**	-	35
Income before income taxes	**9,902**	17,664	2,943
Income tax expense (benefit) -- current	**1,232**	4,851	146
deferred	**1,429**	(928)	-
Net Income	**$ 7,241**	$ 13,741	$ 2,797
Earnings Per Share:			
Basic Earnings Per Share	**$ 0.23**	$ 0.48	$ 0.11
Diluted Earnings Per Share	**$ 0.22**	$ 0.48	$ 0.10
Weighted average number of common shares outstanding:			
Basic	**31,916**	28,444	26,066
Diluted	**33,247**	28,885	26,971

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	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehen-sive Loss	Treasury Stock	Total
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
Comprehensive income:							
Net income for the year	-	-	-	13,741	-	-	13,741
Deferred hedge losses - net of $1,055 in income tax benefit	-	-	-	-	(1,826)	-	(1,826)
Total comprehensive income							11,915
Balance at December 31, 2005	29,480	295	89,680	(4,622)	(1,826)	(246)	83,281
Stock grants	331	3	-	-	-	-	3
Common stock options & warrants exercised	419	4	793	-	-	-	797
Issuance of common stock - net of expenses of $1,735	3,061	31	30,428	-	-	-	30,459
Non-cash compensation	-	-	1,207	-	-	-	1,207
Comprehensive income:							
Net income for the year	-	-	-	7,241	-	-	7,241
Deferred hedge gain - net of $372 in income taxes	-	-	-	-	664	-	664
Total comprehensive income							7,905
Balance at December 31, 2006	33,291	$ 333	$ 122,108	$ 2,619	$ (1,162)	$ (246)	$ 123,652

See notes to audited consolidated financial statements.

THE EXPLORATION COMPANY
Consolidated Statements of Cash Flows

(in thousands)	Years Ended December 31 2006	2005	2004
Operating Activities			
Net income	**$ 7,241**	$ 13,741	$ 2,797
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**24,056**	12,597	9,851
Impairments and abandonments	**1,722**	1,406	2,354
Minority interest in income of subsidiaries	**-**	-	(35)
Loss (gain) on sale of assets	**8**	(24,540)	-
Deferred tax expense (benefit)	**1,560**	(928)	-
Non-cash interest expense and accretion of liability - redeemable preferred stock	**-**	684	1,016
Non-cash stock compensation expense	**1,207**	-	237
Non-cash derivative mark-to market (gain) loss	**(1,995)**	2,128	(134)
Non-cash change in components of OCI	**806**	-	-
Payment to terminate cash flow hedge	**-**	(2,356)	-
Changes in operating assets and liabilities:			
Receivables	**213**	(984)	(4,147)
Prepaid expenses and other	**747**	(469)	(81)
Accounts payable and accrued expenses	**(2,342)**	44	4,636
Current income taxes (receivable) payable	**(8,499)**	4,937	(47)
Net cash provided by operating activities	**24,724**	6,260	16,447
Investing Activities			
Development and purchases of oil and gas properties	**(52,927)**	(49,672)	(39,335)
Purchase of other equipment	**(6,941)**	(37)	(224)
Proceeds from sale of oil and gas properties and other assets	**23**	78,002	-
Changes in minority interests	**-**	-	(159)
Net cash provided (used) by investing activities	**(59,845)**	28,293	(39,718)
Financing Activities			
Proceeds from bank credit facility	**13,450**	15,001	19,099
Payments on bank credit facility	**(11,100)**	(32,099)	(17,295)
Payments on installment and other obligations	**(489)**	(1,761)	(593)
Proceeds from installment and other obligations	**494**	356	377
Redemption of preferred stock	**-**	(16,000)	-
Proceeds from common stock transactions, net of expenses	**30,565**	2,915	18,620
Net cash provided (used) by financing activities	**32,920**	(31,588)	20,208
Change in Cash and Equivalents	**(2,201)**	2,965	(3,063)
Cash and Equivalents at Beginning of Year	**6,083**	3,118	6,181
Cash and Equivalents at End of Year	**$ 3,882**	$ 6,083	$ 3,118
Supplemental Disclosures			
Cash paid for interest	**$ 213**	$ 3,224	$ 3,011
Cash paid for income taxes	**10,581**	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 wholly-owned subsidiaries. The subsidiaries own and operate a gas gathering system and well drilling and servicing equipment. 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 2005 and 2004, none of which were significant, have been reclassified to conform to the 2006 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, 2006, 2005 and 2004. 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, warrants and restricted stock.

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. At December 31, 2006, the Company had deposits in excess of federal insurance protection totaling approximately $2.5 million. 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. Collateral is generally not required. 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 changes in 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

2005 Asset Sale: In accordance with U.S. generally accepted accounting principles, primarily SFAS No. 19, the September 2005 purchase and sale agreement with EnCana Oil & Gas (USA) Inc. was accounted for as a sale of proved and unproved properties for cash. The assets sold included the sale of entire interests in proved properties and the sale of entire interests or partial interests in unproved properties. Proceeds from the sale of entire interests in proved properties were applied towards the unamortized cost of the properties and gain was recorded as appropriate. Proceeds from the sale of interests in unproved properties were treated as recovery of costs and gain was recognized when the sales proceeds exceeded the original cost of the properties.

Accounting for Stock Based Compensation: The Company's stock-based employee compensation plan, described more fully in the Stockholders' Equity footnote, is accounted for 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 was 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 1 of "Recent Accounting Pronouncements" below for disclosure of 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**
Net income as reported	$ 13,741	$ 2,797
Deduct: Total stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects	(342)	(284)
Pro forma earnings	$ 13,399	$ 2,513
Earnings per common share:		
Basic, as reported	$ 0.48	$ 0.11
Basic, pro forma	0.47	0.10
Diluted, as reported	0.48	0.10
Diluted, pro forma	0.46	0.09

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: The Company has 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 by the Board of Directors. Contributions to the Plan by the Company totaled $75,200 in 2006, $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.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - continued

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 Company adopted the requirements effective January 1, 2006. The impact to the Company for options and warrants currently granted was $129,600 in 2006. Basic and diluted earnings per share for 2006 are each $0.004 lower than if the Company had continued to account for share-based compensation under APB 25.

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 2005. The adoption of FSP FAS 19-1 did not impact the Company's consolidated financial position or results of operations.

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement 109." Interpretation 48 prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Benefits from tax positions should be recognized in the financial statements only when it is more likely than not that the tax position will be sustained upon examination by the appropriate taxing authority that would have full knowledge of all relevant information. A tax position that meets the more-likely-than-not recognition threshold is measured at the largest amount of benefit that is greater than fifty percent likely of being realized upon ultimate settlement. Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not recognition threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met. Interpretation 48 also provides guidance on the accounting for and disclosure of unrecognized tax benefits, interest and penalties. Interpretation 48 is effective for the Company on January 1, 2007, and is not expected to have a significant impact on its financial statements.

NOTE B - PROPERTY AND EQUIPMENT

Property and equipment consists of the following at December 31:

(in thousands)	**2006**	**2005**
Oil and gas properties	$ 164,014	$ 124,511
Other property and equipment	8,650	1,952
Total Property and Equipment	172,664	126,463
Accumulated depreciation, depletion and amortization	(50,520)	(39,593)
Reserve for impairment on unproved properties	(2,570)	(2,403)
Net Property and Equipment	$ 119,574	$ 84,467

Proposed Acquisition: On February 20, 2007, we signed an agreement to purchase Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase is $91.6 million in cash, subject to certain adjustments, and $4.0 million of TXCO common stock. The transaction, the largest in TXCO's history, will double our proved reserves and increase current oil and gas production by nearly two thirds. The core of the Output holdings is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk and Eagleford/Woodbine formations. Other Output holdings to be acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf of Mexico waters. Closing is expected on or about April 2, 2007.

NOTE C - DEBT

Debt consists of the following at December 31:

($'s in thousands)	**2006**	**2005**
Long-term:		
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.	$ 2,351	$ 1
Short-term:		
Installment notes to finance company on insurance policies, with interest from 6.00% to 7.95%, monthly installments of $34, and unsecured.	-	262
Installment notes to finance company on insurance policies, with interest from 7.0% to 7.5%, monthly installments of $37, and unsecured	267	-
Total debt	$ 2,618	$ 263

The following is a schedule of principal maturities of debt as of December 31, 2006:

Year Ended December 31,	**Amount** *(in thousands)*
2007	$ 267
2008	2,351
2009	-
	$ 2,618

NOTE C - LONG-TERM DEBT - continued

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.

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 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, 2006, the borrowing base, inclusive of tranche A and tranche B, stood at $32.0 million. The unused borrowing base at March 1, 2007, was $13.3 million, with $18.7 million outstanding at an average interest rate of 8.25%. 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.

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, restrictions on 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, 2006, the Company was in compliance with all covenants.

Commitment for New Revolving Credit Facility: Subsequent to year-end and in connection with the proposed acquisition, the Company signed a commitment letter with BMO Capital Markets Corp. and the Bank of Montreal to enter into a new, four-year senior secured revolving credit facility and a new, five-year secured second-lien term loan facility (the "New Facilities") to fully finance the acquisition, as well as, refinance the existing Facility and provide working capital. The New Facilities will be administered by Bank of Montreal, are collateralized by all of the Company's proven oil and gas properties and contain terms and conditions consistent with similarly positioned companies. The aggregate notional principal amounts are $125.0 million and $80.0 million for the senior revolving credit facility and senior second lien, respectively. TXCO has paid a $100,000 acceptance fee and will be responsible to pay an arrangement fee of approximately $1.9 million upon initial funding of the New Facilities at the closing date of the acquisition. Upon closing, this revolving credit facility will replace the existing facility with Guaranty Bank.

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.

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:

	Amount *(in thousands)*
Balance, December 31, 2004	$ 1,680
Liabilities incurred	103
Liabilities settled	(218)
Accretion expense	-
Balance, December 31, 2005	1,565
Liabilities incurred	131
Liabilities settled	-
Accretion expense	7
Balance, December 31, 2006	$ 1,703

NOTE E - COMMITMENTS AND CONTINGENCIES

The Company leases its primary office space through March 2014, and has maintenance contracts on certain equipment through November 2011. The Company incurred rent expense of approximately $939,000 in 2006, $989,000 in 2005 and $582,000 in 2004. Future minimum rentals under all non-cancelable leases and contracts are as follows:

Year Ended December 31,	**Amount** *(in thousands)*
2007	$ 507
2008	585
2009	592
2010	567
2011	522

NOTE F - STOCKHOLDERS' EQUITY

Preferred Stock: The Company has authorized 10 million shares of preferred stock. At December 31, 2006, there were no Series A or Series B 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.

Private Placements - 2006: In March 2006, TXCO closed on a private placement of 3.0 million shares of its common stock at a purchase price of $10.50 per share for net proceeds of $29.9 million. Purchasers were private, U.S.-based investment funds and individuals. Proceeds from the private placement were used to expand the Company's capital expenditure program in the Maverick and Marfa Basins.

Restricted Stock - 2006: The Company issued 61,335 restricted common shares as partial payment for certain overriding royalty interests.

Restricted Stock - 2005: The Company issued 450,000 restricted common shares as partial payment for certain oil and gas property.

NOTE F - STOCKHOLDERS' EQUITY - continued

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.

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 stockholders 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 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, 2006.

Dividend Restriction: The Bank Credit Facility limits the declaration, or payment, of dividends to no more than 50% of net income for the prior year-end.

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, 2006, 3,319,090 shares were authorized for grant and 1,051,840 shares remained available for grant. All currently outstanding options have 10-year terms that vested and became 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:

	2006	2005	2004
Risk-free interest rate	*	*	3.35%
Expected dividend yield	*	*	0%
Expected volatility of common stock	*	*	.47
Expected weighted-average life of option	*	*	5 years

* No grants of stock options were awarded during 2005 or 2006.

NOTE F - STOCKHOLDERS' EQUITY - continued

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.

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

	Shares *(in thousands)*	**Weighted Average Exercise Price**	**Weighted Average Fair Value of Options Granted**	**Shares Exercisable at End of Period** *(in thousands)*
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	N/A	
Exercised	(529)	3.15		
Forfeited	(33)	5.56		
Outstanding at December 31, 2005	1,254	2.86		864
Granted	-	N/A	N/A	
Exercised	(293)	2.69		
Forfeited	(5)	5.00		
Outstanding at December 31, 2006	956	$2.90		856

The following table summarizes information about the options outstanding at December 31, 2006:

	Options Outstanding			**Options Exercisable**	
Exercise Price	**Number Outstanding** *(in thousands)*	**Wt.-Avg. Remaining Contractual Life**	**Wt.-Avg. Exercise Price**	**Number Exercisable** *(in thousands)*	**Wt.-Avg. Exercisable Price**
$2.12	579	1.70 years	$2.12	479	$2.12
2.96	72	4.59 years	2.96	72	2.96
3.09	75	2.08 years	3.09	75	3.09
4.38	81	6.47 years	4.38	81	4.38
5.00	149	7.75 years	5.00	149	5.00
	956		$2.86	856	$2.90

NOTE F - STOCKHOLDERS' EQUITY - continued

Stock Warrants*:* The following is a summary of warrants outstanding at December 31, 2006:

Purpose of Warrants	Number of Shares *(in thousands)*	Range of Prices	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
Financing	927	$4.25	$4.25	0.7 year

Restricted Stock: In first-quarter 2006, 349,000 shares of restricted stock were granted, under the 2005 Stock Incentive Plan, to directors and employees of the Company. Of these shares, 40,000 had a one-year vesting period, while the remaining shares vest over a three-year period. Compensation expense is recognized over the vesting periods, with $1.0 million expensed during 2006, and $1.2 million and $0.8 million estimated to be expensed in 2007 and 2008, respectively.

	(in thousands)
Outstanding at December 31, 2005	-
Granted	349
Forfeited	(18)
Vested	(1)
Outstanding at December 31, 2006	330

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, 2006 and 2005:

(in thousands)	**2006**	**2005**
Net income	$ 7,241	$ 13,741
Other comprehensive income (loss):		
Deferred hedge gain (loss)	1,036	(2,881)
Income tax (expense) benefit of cash flow hedges	(372)	1,055
Total comprehensive income	$ 7,905	$ 11,915

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, 2006:					
Basic EPS:					
Net income	31,916	$	7,241	$	$0.23
Effect of dilutive options	1,331		-		0.01
Dilutive EPS	33,247	$	7,241	$	$0.22
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

NOTE I - INCOME TAXES

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

(in thousands)		**2006**		**2005**		**2004**
Current federal tax (benefit) expense	$	1,232	$	4,851	$	146
Deferred federal tax expense (benefit)		1,429		(928)		-
Income tax expense	$	2,661	$	3,923	$	146
Deferred tax assets:						
Tax net operating loss carryforwards	$	-	$	-		
Impairment of oil and gas properties		8,258		6,955		
Restricted stock compensation		399		-		
Mark-to-market loss on cash flow hedges		683		738		
Gross deferred tax assets		9,340		7,693		
Deferred tax liabilities:						
Intangible drilling costs		(3,304)		-		
Depreciation differences		(726)		(451)		
Gross deferred tax liabilities		(4,030)		(451)		
Net deferred tax assets	$	5,310	$	7,242		

NOTE I - INCOME TAXES - continued

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

(in thousands)	2006	2005	2004
Expected federal tax expense	$ 3,664	$ 6,535	$ 1,088
Change in valuation allowance	-	(1,642)	(1,350)
Permanent difference on exercise of stock options	(698)	-	-
Other changes, including statutory tax depletion and domestic production deduction	(305)	(970)	408
Income tax expense	$ 2,661	$ 3,923	$ 146

NOTE J - 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, 2006	12%	10%	8%	2%	-%	-%
Year ended December 31, 2005	11%	5%	11%	14%	17%	-%
Year ended December 31, 2004	2%	-%	13%	5%	14%	13%

NOTE K - COMMODITY HEDGING CONTRACTS AND ACTIVITY

Due to the volatility of oil and natural gas prices and former 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, 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 is being 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.

NOTE K - COMMODITY HEDGING CONTRACTS AND ACTIVITY - continued

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 terminated derivatives remained in the contra-equity account and is now being applied against revenue as the hedged transactions occur.

The following table lists contracts outstanding as of December 31:

Transaction				Price Per	Barrels Per	Fair Value of Outstanding Derivative Contracts as of December 31, *(1)*	
Date	**Type**	**Beginning**	**Ending**	**Unit**	**Month**	**2006**	**2005**
Crude oil (2):						*(in thousands)*	
Derivatives treated as investments:							
03/05 ***(3)***	Fixed Price	11/01/2005	10/31/2006	$49.40	15,000	n/a	$(1,995)
Derivatives treated as cash flow hedges:							
06/05	Fixed Price	11/01/2006	04/30/2007	$56.70	13,000	$(321)	(550)
Total fair value of derivative contracts						$(321)	$(2,545)

(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.
(3) This crude oil hedge expired in October 2006.

NOTE L - SALES OF OIL AND GAS PROPERTIES

February 2005 Asset Exchange: In February 2005, the Company entered into an agreement with Arrow River Energy LP and CMR Energy LP. Under this agreement TXCO acquired an interest in certain leasehold acreage, in exchange for giving an interest in certain other leasehold acreage. The exchange of interests was accounted for as a conveyance of property that is a transfer of assets used in oil and gas producing activities (primarily unproved properties) in exchange for other assets (primarily unproved properties) also used in oil and gas producing activities. The book value of the properties exchanged was approximately $5.5 million. The net book value of the conveyed assets prior to conveyance was allocated (based on percent interest retained/conveyed) to the assets remaining after conveyance and the assets received in exchange. There was no change in the net book value of retained unproved properties as a result of the transaction; hence no gain or loss was recognized at the time of conveyance. Based on the Company's evaluation, the fair market value of the leasehold acreage received was equivalent to that of the leasehold acreage conveyed.

September 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. In accordance with U. S. generally accepted accounting principles, primarily SFAS No. 19, the September 2005 purchase and sale agreement with EnCana was accounted for as a sale of proved and unproved properties for cash. The assets sold included the sale of entire interests in proved properties and the sale of entire interests or partial interests in unproved properties. Proceeds from the sale of entire interests in proved properties were applied towards the unamortized cost of the properties and gain was recorded as appropriate. Proceeds from the sale of interests in unproved properties were treated as recovery of costs and gain was recognized when the sales proceeds exceeded the original cost of the properties. A pre-tax gain of $24.5 million was recognized on this transaction in the third quarter.

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)	**2006**	**2005**
Proved properties	$ 147,681	$ 91,768
Less accumulated depreciation, depletion and amortization	(70,574)	(38,404)
Net proved properties	77,107	53,364
Unproved properties:		
Drilling in-progress	30,623	21,738
Oil and gas leasehold acreage	5,941	9,955
Coalbed methane properties	1,056	1,050
Total unproved properties	37,620	32,743
Less reserve for impairment	(2,570)	(2,403)
Net unproved properties	35,050	30,340
Net capitalized cost	$ 112,157	$ 83,704

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

(in thousands, except per equivalent mcf data)	**2006**	**2005**	**2004**
Property acquisition costs, unproved	$ 18,670	$ 9,684	$ 11,107
Property development and exploration costs:			
Conventional oil and gas properties	51,293	31,903	31,873
Coalbed methane properties	3	76	314
Gathering system	113	388	101
Depreciation, depletion and amortization	23,627	12,377	9,646
Depletion per equivalent mcf of production	4.04	2.69	1.97

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.

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)	**2006**	**2005**	**2004**
Proved developed and undeveloped reserves:			
Natural gas (mmcf):			
Beginning of year	9,656	17,701	15,624
Extensions and discoveries	198	5	6,432
Reserves purchased	-	-	557
Sales volumes	(1,104)	(2,222)	(2,975)
Revisions of previous engineering estimates	(795)	(2,844)	(1,937)
Reserves transferred	-	(2,984)	-
End of year	7,955	9,656	17,701
Crude Oil (mBbl):			
Beginning of year	4,957	3,374	2,129
Extensions and discoveries	778	522	1,396
Reserves purchased	-	-	-
Sales volumes	(791)	(397)	(321)
Revisions of previous engineering estimates	636	1,187	170
Reserves transferred	-	271	-
End of year	5,580	4,957	3,374
Proved developed reserves:			
Natural gas (mmcf):			
Beginning of year	7,846	13,087	9,896
End of year	6,286	7,846	13,087
Crude Oil (mBbl):			
Beginning of year	1,813	1,688	1,340
End of year	2,262	1,813	1,688

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 $5.40, $7.775 and $6.06 per mcf of gas and $57.75, $57.75 and $41.15 per barrel of oil as of December 31, 2006, 2005 and 2004. 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.

(in thousands)	**2006**	**2005**	**2004**
Future cash inflows	$ 371,475	$ 379,431	$ 246,073
Future production and development costs	(182,459)	(167,659)	(113,353)
Future income tax expense	(37,901)	(53,419)	(25,152)
Future net cash flows	151,115	158,353	107,568
10% annual discount to reflect timing of net cash flows	(49,096)	(60,330)	(42,106)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 102,019	$ 98,023	$ 65,462

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

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)	**2006**	**2005**	**2004**
Standardized measure, beginning of year	$ 98,023	$ 65,462	$ 47,349
Extensions and discoveries	32,880	19,410	46,763
Reserves purchased	-	-	2,533
Sales and transfers, net of production costs	(46,721)	(29,882)	(23,133)
Revisions in quantity and price estimates	(1,280)	49,085	(6,923)
Net change in income taxes	9,315	(12,598)	(5,862)
Accretion of discount	9,802	6,546	4,735
Standardized measure, end of year	$ 102,019	$ 98,023	$ 65,462

NOTE N - Selected Quarterly Financial Information (Unaudited)

(In thousands, except earnings per share data)	**First**	**Second**	**Third**	**Fourth**	**Total**
2006					
Total revenues	$ 16,023	$ 19,552	$ 21,583	$ 15,260	$ 72,418
Income (loss) from operations ***(1)***	2,799	6,951	8,369	(7,583)	10,536
Net income (loss)	1,275	3,981	6,388	(4,403)	7,241
Earnings Per Share: ***(2)***					
Basic	$ 0.04	$ 0.12	$ 0.20	$ (0.13)	$ 0.23
Diluted	0.04	0.12	0.19	(0.13)	0.22
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	(3,302)	(1,018)	15,288	2,773	13,741
Earnings Per Share: ***(2)***					
Basic	$ (0.12)	$ (0.04)	$ 0.54	$ 0.10	$ 0.48
Diluted	$ (0.12)	$ (0.04)	$ 0.53	$ 0.09	$ 0.48

(1) Income from operations and net income were down significantly in the fourth quarter of 2006, primarily as the result of increased depletion booked in that period due to the rapid depletion of six wells put on production in quarters three and four.

(2) 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, 2006				
Allowance for doubtful accounts, trade accounts	$ 27	$ -	$ -	$ 27
Impairment of oil and gas properties	2,403	167	-	2,570
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