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, 2007

OR

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

Commission File Number 0-9120

TXCO Resources 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 ☐	Smaller-reporting company ☐

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

On June 30, 2007 (the end of registrant's second quarter), the aggregate market value of the its common stock held by its non-affiliates was $336.6 million, based on the $10.28 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, 2008, was 34,880,724.

Documents Incorporated by Reference: Portions of the Company's Definitive Proxy Statement for the Annual Stockholders' Meeting, to be held on May 9, 2008 are incorporated by reference into Items 10, 11, 12, 13 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 estimated financial results, or expected prices, production volumes, well test results, reserve levels and number of drilling locations, 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, and outcomes of legal proceedings. 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. TXCO undertakes no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise. Please refer to the Risk Factors discussion in Part I, Item 1A for additional information.

PART I

ITEM 1. BUSINESS

GENERAL

At the 2007 Annual Stockholders' Meeting, our stockholders approved the change of the Company's name to TXCO Resources Inc. from The Exploration Company of Delaware, Inc. 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[SM] is TXCO. Unless the context requires otherwise, when we refer to "TXCO", "the Company", "we", "us" and "our", we are describing TXCO Resources 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, 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 Filings" link on the "Governance" menu. You may obtain free of charge a copy of the reports (and any amendment thereto) 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, and 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.

As of December 31, 2007, we employed 105 full-time employees including management. We believe our relations with our employees are good. None of our employees are covered by union contracts.

We are an independent oil and gas enterprise with interests in the Maverick Basin of southwest Texas, the Fort Trinidad area in east Texas, the onshore Gulf Coast region and the Marfa Basin of Texas, the Midcontinent region of western Oklahoma, and shallow Gulf of Mexico waters. Our primary business operation is exploration, exploitation, development, production and acquisition of predominately 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.

LONG-TERM STRATEGY

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 other 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 asset base in the Maverick Basin, we own a natural gas gathering system with over 90 miles of pipeline 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, we are evaluating opportunities in our Marfa Basin acreage.

We have taken another step in expanding beyond these core areas through the acquisition of Output Exploration, LLC ("Output"), a privately held, Houston-based exploration and production firm on April 2, 2007. The core of the Output holdings, in the East Texas Fort Trinidad Field, is prospective for the Glen Rose, Buda, Austin Chalk, Eagleford / Woodbine and Bossier formations. Other Output assets acquired include acreage in the Midcontinent region of western Oklahoma, the Gulf Coast region and shallow Gulf of Mexico waters.

RECENT DEVELOPMENTS

2007 Drilling Activity Summary: We participated in drilling a total of 87 gross wells during 2007. Maverick Basin wells totaled 71, including 19 re-entries. We participated in 12 wells on former Output assets, three wells in the Williston Basin and one well in the Marfa Basin. Additionally, four wells that were in completion at the beginning of the year resulted in producing well completions during 2007.

Reserve Growth: We continued our ongoing trend of annual reserve growth in 2007 by recording net proved reserve additions of 50.3 billion cubic feet equivalent ("Bcfe"). Combined with annual production of 8.0 Bcfe, our gross reserve additions for the year were 58.3 Bcfe. Estimated year-end proved oil and gas reserves reached 91.8 Bcfe, a 121.7% increase above the 41.4 Bcfe at year-end 2006. We achieved a 731.4% all-source reserve replacement rate in 2007.

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 -- most above 7,000 feet, in addition to the acquisition of Output.

Exploration, exploitation and development targets for 2008, 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;
- additional horizontal wells targeting Glen Rose porosity oil production;
- vertical wells targeting gas from the Pearsall Shale and Sligo formations;
- continued horizontal and vertical drilling for Glen Rose shoal gas intervals on our Fort Trinidad leases;
- exploration of the Barnett and Woodford shales in the Marfa Basin;
- an additional well to the Jurassic formation; and
- wells targeting the Springer-Morrow sands in the Anadarko 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.

2008 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 2008. We established a range of $100 million to $110 million for our 2008 capital expenditure budget ("CAPEX"), with 97 planned wells targeting multiple horizons and fields. We plan to participate in 83 wells in seven different horizons in the Maverick Basin, including the Glen Rose Porosity (35 wells, $40.7 million), San Miguel Oil Sands (eight wells, $10.0 million), Pena Creek San Miguel (20 wells, $10.0 million), Pearsall (2 wells, $7.0 million) and Austin Chalk (11 wells, $4.9 million), as well as expenditures for participation in six Georgetown and one Jurassic wells. On former Output assets, we expect to invest almost $20 million by participating in 10 wells in the Fort Trinidad field and four wells in the Midcontinent area. In the Marfa Basin, prospective for the Woodford or Barnett shales, we have allocated approximately $1.5 million for exploration and development work. Other items in the budget, including leasing and infrastructure projects, are earmarked for $5.0 million.

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 continue to be profitable in 2008, and further expect to have sufficient working capital available from traditional sources, including cash on hand from our recent preferred stock offerings, cash flow from operations and borrowings from our reserve-based bank credit facility. 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.

Output Acquisition: On April 2, 2007, we closed on the purchase of Output Exploration, LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase was $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, effectively doubled our proved reserves and increased our oil and gas production by nearly two thirds, both from pre-acquisition levels. The core of the Output holdings, in the East Texas Fort Trinidad Field, is prospective for the Glen Rose, Buda, Austin Chalk, Eagleford / Woodbine and Bossier formations. Other Output assets acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf of Mexico waters. Additional information regarding our 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 2007, we spudded or re-entered a total of 71 wells in various horizons in the Maverick Basin, 12 wells on former Output acreage, three in the Williston Basin, and one in the Marfa Basin. These totals compared to 56, none, one and one, respectively, in 2006. Of the 87 total wells begun in 2007, 56 have been placed on production through February 2008, including 43 oil wells in the Glen Rose, Austin Chalk, San Miguel, Georgetown, and Red River formations, and six gas wells completed in the Glen Rose and Pearsall formations in the Maverick Basin and two oil wells and five gas wells completed on former Output holdings, while two were plugged and abandoned.

Our strategy remains focused primarily on our core oil and natural gas producing properties and higher margin exploration, exploitation and development activities in the Maverick Basin, while selectively developing opportunities in our newly acquired Output properties and continuing to evaluate 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.

At year-end 2007, we had an average working interest ("WI") of over 85% on our Maverick Basin leasehold acreage (over 700,000 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. At year-end 2007, we also had an average WI over 85% on our Fort Trinidad leasehold acreage, which was approximately 18,000 gross acres.

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 2007, we acquired an additional seven square miles of 3-D seismic data in the Maverick Basin. At year-end 2007 we had accumulated over 953 square miles of 3-D seismic data covering more than 86% of our 1,100-square-mile 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 CAPEX projects for 2008:

		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 Maverick Basin Glen Rose - Oil and Gas	48% to 100%
6	Pearsall Shale - Gas	12.5% to 100%
7	Barnett and Woodford Shales - Gas	50%
8	Fort Trinidad Glen Rose	50% to 100%

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 2007, our working interest in much of our non-operated, 95,250-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.

Nine new wells and five re-entries were drilled on the Comanche Ranch and Chicon Creek leases during 2007 with our operating partners. Additionally, during 2007 we drilled or re-entered 21 Glen Rose oil wells on the adjacent Cage and Glass Ranches, where we hold a 100% WI. Of the combined 35 wells drilled or re-entered targeting the porosity zone, 22 were producing oil at year-end 2007, 12 were to be completed or re-completed, while one was re-entered targeting the Eagleford zone. Since year-end, one additional 2007 well has begun production. By comparison, we drilled or re-entered 31 Glen Rose oil wells during 2006.

Glen Rose oil sales for 2007 totaled 714,000 barrels of oil ("BO") up from 689,000 BO during 2006. The combined number of wells drilled since the oil play's discovery in February 2002 stands at 93 through year-end 2007. Cumulative Glen Rose gross oil production since its discovery surpassed 4.8 million barrels of oil through February 2008. 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, 2007, for the Glen Rose oil porosity zone are estimated at 1.6 million BO, equivalent to 9.9 Bcfe, up from 1.5 million (9.0 Bcfe) for the prior year. We believe that significant additional proved reserves will be established in the future.

During 2007, we contracted with Schlumberger to conduct a comprehensive reservoir optimization study of the porosity, which is anticipated to be concluded during April 2008. The project will help us determine the best method to locate, drill and complete wells to maximize oil production.

We spudded five porosity wells thus far in 2008. Two wells currently await completion while three wells continue drilling. Our 2008 CAPEX includes $40.7 million for 35 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. 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 34 horizontal Glen Rose gas wells, with two wells awaiting completion.

We spudded six Glen Rose shoal or reef wells during 2007, compared to two wells in 2006. One of the reef wells was later recompleted to the Georgetown formation. Glen Rose gas sales for 2007 totaled 0.8 Bcf, compared to 1.0 Bcf during 2006. The field produced more than 14.3 Bcf since horizontal drilling techniques were first applied in 2001. At December 31, 2007, net proved gas reserves for Glen Rose were estimated at 7.0 Bcfe, compared to 7.7 Bcfe for the prior year. The 2008 CAPEX does not include funds for Maverick Basin Glen Rose shoal or reef wells.

Georgetown: During 2007, we spudded three new Georgetown wells and re-entered three wells, as compared to four Georgetown wells drilled or re-entered in 2006. Of the six 2007 Georgetown wells, two wells are producing oil, while four wells remain in completion. Additionally, one well that originally targeted a Glen Rose reef was recompleted to the Georgetown, and is producing oil. Georgetown gas sales for 2007 totaled 38.4 mmcf, compared to 52.5 mmcf during 2006, while Georgetown oil sales increased to 14,300 BO from 13,200 BO in 2006. The current 2008 CAPEX includes $3.0 million for six new wells. We have participated in three Georgetown wells this year through February 2008. Most of the wells will be drilled to hold leases for deeper horizons.

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 increased to 0.7 Bcfe from 0.3 Bcfe at year-end 2006.

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 2007, we began eight infill wells targeting bypassed reserves, one well extending the reservoir and two wells not in the waterflood zone. Of these, at December 31, 2007, nine are producing oil, one is awaiting completion and one was plugged and abandoned. During 2006, we drilled and successfully completed 15 wells. San Miguel oil sales in 2007 were 78,700 BO, compared to 66,200 BO in 2006. Net proved reserves at year-end for this field were estimated at 3.9 million barrels, equivalent to 23.2 Bcfe, down slightly from 4.0 million barrels (23.8 Bcfe) at year-end 2006. The 10,000-acre Pena Creek prospect is contiguous to our Comanche Ranch lease. 2008 CAPEX includes $10.0 million for 20 new wells in the San Miguel waterflood.

Pearsall Shale: During 2007 we participated in four wells targeting the Pearsall formation. At year end, two were producing natural gas, while two were awaiting completion. We are continuing to evaluate production from these vertical completions and expect to complete a multi-stage fracture stimulation on a horizontal Pearsall well (50% WI) soon. We modified our agreement with EnCana during 2007 to earn additional interests in this formation by carrying them on three wells by the end of July 2008. Through February 2008, we have begun two of the three wells required to earn the additional interests in the first phase. We can further increase our interest in the play by drilling an additional four wells by the end of July 2009.

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. The data gathering well was 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 represented our first major investment in this promising formation that underlies approximately 521,000 acres of our Maverick Basin deep-rights leaseholdings. The Pearsall Shale is an over-pressured shale play.

Our 2008 CAPEX includes $7.0 million for drilling two new wells in the Pearsall Shale formation on our Comanche lease block. One of these wells was spud in February 2008 and continues drilling.

Oil Sands: The San Miguel Oil Sands feature ("Oil Sands") is prospective under approximately 77,000 acres of 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 contiguous acres over the deposit.

To date, we have successfully completed our initial, two-well cyclic steam pilot phase, having mobilized the oil and established a preliminary, favorable WTI price differential from area refiners. Based on continuing reservoir simulation studies, we have decided to convert this pilot to a Steam-Assisted Gravity Drainage ("SAGD") process by the addition of two horizontal wells. We used our recently purchased shallow drilling rig to drill two horizontal wells in this conversion. The SAGD technique is used extensively in the Athabasca tar sands in Canada. This marks the first time that a SAGD pilot will be applied to the San Miguel oil sands.

The SAGD well pair was drilled between the existing cyclic steam wells, which will be converted to temperature-monitoring wells. Existing steam generation capacity will be doubled by the addition of a second 25 mmBtu steam generator, expected to be delivered in March 2008.

We are also further utilizing our new drilling rig to establish a second pilot during the first half of 2008, featuring five to eight new horizontal/vertical wells utilizing a modified Fracture-Assisted Steamflood Technology (FAST), a technique proven by Conoco in years past. The wells are being drilled on a schedule consistent with expected deliveries of two new 50 mmBtu steam generators in second-quarter 2008. Based on the results from the pilot wells, our 2008 CAPEX includes $10.0 million for San Miguel Oil Sands wells and related steam generators and surface equipment. Our partner is also contributing $10 million to this $20 million project.

In December 2007, we engaged Scotia Waterous -- a global leader in oil and gas industry mergers, acquisitions and capital market transactions -- as financial advisor for a strategic alternatives effort to maximize the value of our oil sands assets. Most of our wholly owned oil sands assets have been placed in a wholly owned subsidiary designed to expedite development opportunities. No formal decisions have been made and no agreements have been reached at this time. There can be no assurance regarding the timing of, or whether, this process will result in any type of agreement. We do not intend to provide updates until a definitive transaction has been approved, if any.

Other Plays: During 2007, we drilled seven wells to the Austin Chalk formation, three of which are producing oil, while four were awaiting completion at December 31, 2007. This compares to one well to the Pryor formation during 2006. Our 2008 CAPEX includes funds for participating in one Jurassic well and 11 Austin Chalk wells to hold leases.

OTHER AREAS

Newly Acquired Assets: On April 2, 2007, we closed on the purchase of Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase was $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, essentially doubled our proved reserves and increased then-current oil and gas production levels by nearly two thirds. The core of the Output assets is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk, Eagleford/Woodbine and Bossier formations. Other Output assets acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf of Mexico waters.

TXCO participated in a total of eight new wells and four re-entries on former Output assets during 2007. Of the 12 total wells that we participated in four were in Oklahoma, four were in Texas, two were in Louisiana and two were in shallow waters off the Louisiana coast. At December 31, 2007, five of these wells were producing, five awaited completion and two continued drilling. Additionally, one well spud in 2006, before our acquisition, began production during 2007. Our 2008 CAPEX includes funds for participation in 10 Fort Trinidad Glen Rose shoal wells and four wells in the Midcontinent region.

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. A fracture stimulation procedure was performed on the well during 2007. Our 2008 CAPEX includes $1.5 million for exploration and development work.

Williston Basin: At December 31, 2007, we retained approximately 4,400 gross and 2,000 net acres in the Williston Basin.

During 2007, we participated in the drilling of one new well (4.2% WI), and two reentries (3.1% and 2.8%) in the Red River formation, all of which are producing oil. In 2006 we participated in one new oil well in this formation. Our 2007 net sales for the Williston Basin totaled 19,600 BO and 26.6 mmcf, as compared to 22,100 BO and 45.0 mmcf in 2006. No funds have been included in the 2008 CAPEX for drilling in this basin.

PRINCIPAL PRODUCTS AND COMPETITION

Our principal products are crude oil and natural gas. The production and marketing of oil and gas are affected by a number of factors beyond our control, the effects of which we can not 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 2007. 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, drill 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 2007, three purchasers of our oil and gas production and other natural gas sales accounted for 40%, 15% and 11% of total revenues. We believe that alternative purchasers could be found for such production at comparable prices if any of these major customers declined to purchase future production.

During 2006, we purchased and refurbished a drilling rig that has the capacity to drill vertical and horizontal wells up to a total measured depth of approximately 10,000 feet. It was placed into service in January 2007 and is currently being used on Glen Rose Porosity wells, for which we have a 100% WI. During 2007, we acquired two additional drilling rigs with lower depth ratings for use on shallow Maverick Basin targets. One of these began drilling operations in October 2007 for wells targeting the San Miguel, for which we have a 50% to 100% WI, while the other is stacked. The rigs allow us to reduce drilling costs on our wells and facilitate 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 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. Prior to 2007, the majority of our revenues have been from Texas with some additional revenues from North Dakota and Montana. With this year's acquisition of Output, in addition to the above states, we also receive revenues in Louisiana, Mississippi and Oklahoma with the majority remaining from Texas. The following table shows the production and severance tax rates received by these various states:

State	Oil	Gas
Texas	4.6%	7.5%
Louisiana	12.5%	$0.269 per mcf
Mississippi	06.0%	6.0%
Montana	17.2%	17.2%
North Dakota	9.0%	11.5%
Oklahoma	7.1%	7.1%

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 2007, we had a tax benefit of $5.3 million resulting from an election to expense intangible drilling costs. With the election to expense intangible drilling costs, the Company will elect to carry-back its tax net operating loss, resulting in a recovery of taxes paid in prior years.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

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

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

Oil and gas drilling is a high-risk activity.

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

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

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

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

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

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

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

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

The marketability of our production depends in part upon the availability, proximity, and capacity of 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 54% 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 can not 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 completed a significant acquisition in 2007 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, the inability to successfully integrate such businesses into our operations, and 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.

Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted.

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 our Common Stock. In November 2007, we issued 55,000 shares of Series C preferred stock, which is currently convertible into approximately 3.8 million shares of our common stock, in a private placement to raise additional capital.

An additional 20,000 shares of Series E convertible preferred stock was issued in February 2008. Concurrently with the issuance of the Series E preferred shares, the buyers of the Series C preferred exchanged their 55,000 issued and outstanding shares of our Series C preferred stock for 55,000 shares of Series D preferred stock. The Series D preferred stock provides for the same conversion price as was on the Series C. Further, a portion of the consideration for our April 2007 acquisition of Output Exploration, LLC was 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.

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. In November 2007, we issued 55,000 shares of Series C preferred stock, which is currently convertible into approximately 3.8 million shares of our common stock, in a private placement to raise additional capital. An additional 20,000 shares of Series E preferred stock was issued in February 2008, which is currently convertible into 1.15 million shares.

The exercise of stock options or warrants would result in dilution of our Common Stock.

To the extent options to purchase Common Stock under our stock incentive plans are exercised, holders of our Common Stock will be diluted. As of March 13, 2008, there were outstanding under our 1995 Flexible Incentive Plan options to purchase an aggregate 312,750 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 711,500 shares of our Common Stock outstanding.

Instituted in 2000, our Rights Plan and certain provisions in our Restated Certificate of Incorporation may inhibit a takeover of the Company.

- Our Rights Plan as amended 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.

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 25,400 square feet, are leased through March 2014 at $0.6 million per year. Additionally, we have an office in the Houston area, consisting of about 6,600 square feet that is leased through August 2012 at $0.1 million per year.

All our oil and gas properties, reserves, and activities are located onshore in the continental United States; except for one property acquired with the Output acquisition that 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, 2007, 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 2005 through 2007. Estimates of proved developed oil and gas reserves attributable to our interest at December 31, 2007, 2006 and 2005 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, 2007, Flint Hills West Texas Intermediate posted price of $92.75 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, 2007, Houston Ship Channel spot market price of $6.445 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)*
2008	$45,448
2009	55,229
2010	56,377
2011	39,796
2012	29,986
Thereafter	146,192
Total PV-10 value	373,028
Less present value of estimated income tax expense	63,058
Standardized measure	$309,970

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.

	2007		**2006**		**2005**	
Proved Oil & Gas Reserves at December 31,	**Volumes**	**Mix ***	**Volumes**	**Mix ***	**Volumes**	**Mix ***
Natural gas (Bcf)	42.3	46%	8.0	19%	9.7	25%
Oil (mmBbls)	8.2	54%	5.6	81%	5.0	75%
Natural gas equivalent (Bcfe) *	91.8	100%	41.4	100%	39.4	100%
Oil equivalent (mmBbls) *	15.3	100%	6.9	100%	6.6	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 (excluding the impact of hedging), and average production costs per unit of production for the periods indicated.

	Years Ended December 31,		
	2007	**2006**	**2005**
Oil:			
Sales volumes in Barrels (Bbl)	974,000	791,000	397,000
Average realized sales price per Bbl	$71.11	$62.56	$54.21
Gas:			
Sales volumes in mcf	2,125,000	1,104,000	2,222,000
Average realized sales price per mcf	$7.26	$7.18	$7.65
Equivalent Units: (1)			
Sales volumes:			
mcfe	7,971,000	5,852,000	4,605,000
BOE	1,328,000	975,000	767,000
Average cost per equivalent: (2)			
mcfe	$2.33	$1.67	$1.88
BOE	$13.97	$10.05	$11.27

(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**
12/31/07	167,043	62,225	407	282.39	370	145.09	777	427.48
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

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. Five of the above wells have multiple completions.

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, 2007, we owned, by lease or in fee, the following undeveloped acres:

United States	Gross Acres	Net Acres	Estimated 2008 Delay Rentals
			($ in thousands)
Texas	807,042	645,180	$1,322
Oklahoma	41,749	4,230	-
Louisiana	5,600	807	-
Total	854,391	650,217	$1,322

Thirteen Texas leases totaling approximately 430,056 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:

	2007		2006		2005	
Completions Summary:	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Drilling Well Completions:						
Oil wells ***(1)***	31	26.59	37	33.47	24	17.76
Gas wells ***(1)***	8	3.23	1	1.00	4	2.00
Dry holes ***(2)***	1	1	2	1.62	-	-
Total Drilling Wells Completed	40	30.82	40	36.09	28	19.76
Re-entries Completed:						
Oil wells	13	8.03	6	5.45	1	1.00
Gas wells	1	0.02	-	-	2	2.00
Injection wells	-	-	1	1.00	-	-
Dry holes	1	0.50	2	1.13	-	-
Total Re-entries Completed ***(3)***	15	8.55	9	7.58	3	3.00
Wells Completed in Year	55	39.37	49	43.67	31	22.76

(1) The 2007 column includes two oil wells and two gas wells spud in prior years and completed in 2007, while the 2006 column includes three oil wells spud in prior years and completed in 2006.
(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: 2007 -- 13, 2006 -- 3, 2005 -- 2.

In-Progress Recap:		2007 Gross	2007 Net	2006 Gross	2006 Net	2005 Gross	2005 Net
Beginning In-Progress ("BIP")		59	45.42	54	40.67	54	41.86
Wells recategorized to in-progress		-	-	-	-	3	2.59
Add -	New re-entries begun not finished	5	4.26	2	1.50	1	0.50
	New wells spud not finished	23	15.98	11	9.50	14	10.11
Less -	Completions of BIP	3	2.50	5	4.00	-	-
	BIP wells transferred to producing	13	11.60	-	-	-	-
	BIP wells fully impaired	8	6.74	-	-	-	-
	BIP wells plugged	1	0.50	3	2.25	-	-
	BIP wells transferred to others	-	-	-	-	18	14.39
Ending In-Progress		62	44.32	59	45.42	54	40.67

2007 Activity: During 2007, we participated in 87 wells, including new drilling of 61 (46.81 net) wells and the re-entry of 26 (8.05 net) existing wells. We operated 43 (39.45 net) of the 61 newly drilled wells. Of the 87 wells begun in 2007, 35 (27.32 net) remained in progress at December 31, 2007. Twelve of the re-entered wells were placed on production as oil wells, one (0.02 net) was placed on production as a gas well and 13 (10.88 net) wells are in completion phase. Additionally, four (2.62) wells spudded during 2006 were completed and put on production in 2007.

At December 31, 2007, in-progress wells included 22 development wells spudded in 2007, 13 re-entries spudded in 2007, and 26 wells that remained in progress from the beginning of 2007. Most of the in-progress wells are being scheduled for recompletion as horizontal wells or into other zones.

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.

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.

GAS GATHERING SYSTEM

We acquired our gathering system in 2002 to enhance our infrastructure in the Maverick Basin, which we have expanded over the intervening years. The system currently consists of over 90 miles of natural gas pipeline, a compressor station with three compressors and three dehydrators that allow a 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. No significant additions were made to the gathering system since 2004.

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,		
	2007	**2006**	**2005**
Residue gas and NGL sales volumes (mmBtu)	1,343,000	1,878,000	3,082,000
Average sales price per mmBtu	$8.25	$8.04	$9.08

ITEM 3. LEGAL PROCEEDINGS

We were not involved in any material matters of litigation as of March 15, 2008.

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 2007.

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 prices per share of our Common Stock for the periods indicated on the NASDAQ Global Select Market.

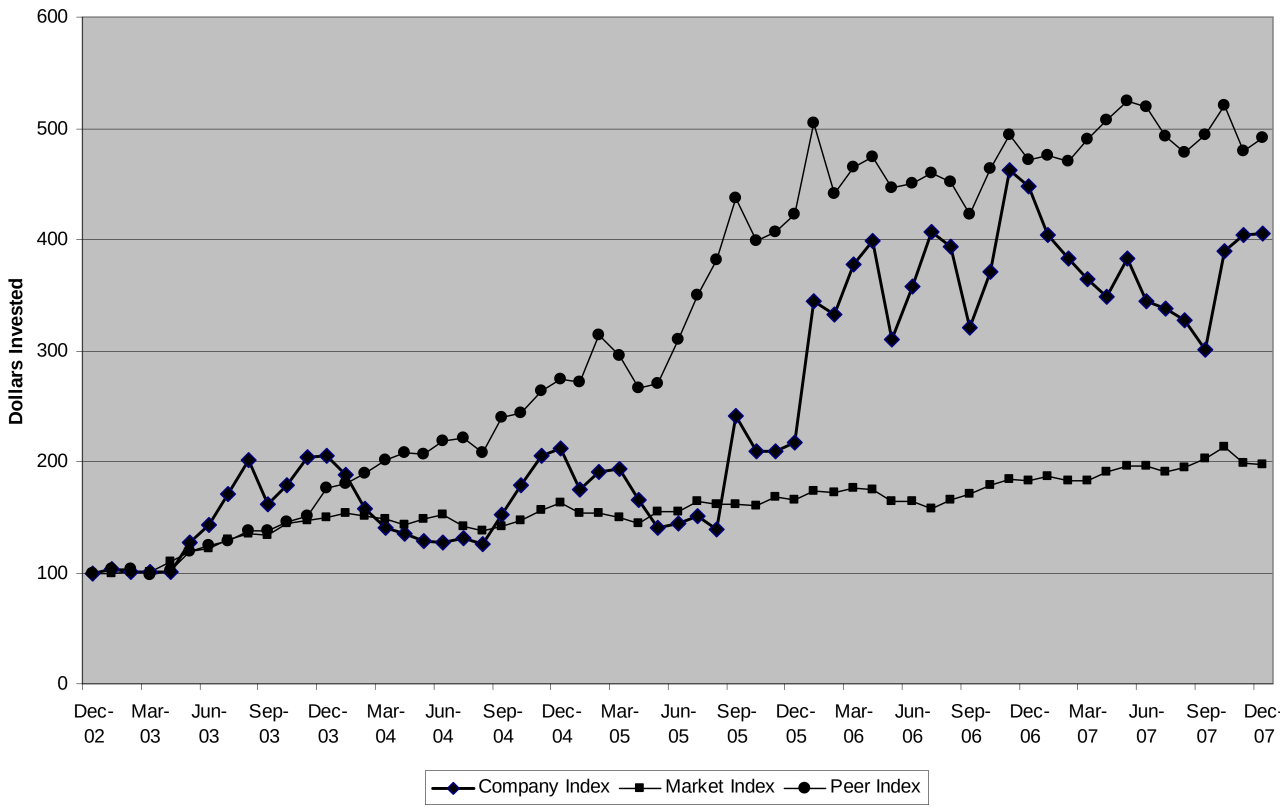
	Range of Sale Prices	
Quarter Ended:	**High**	**Low**
December 2007	$14.08	$8.90
September 2007	12.37	8.46
June 2007	12.27	9.91
March 2007	13.33	8.55
December 2006	$14.62	$8.76
September 2006	13.26	8.68
June 2006	12.77	8.84
March 2006	13.09	6.40

As of March 10, 2008, there were 1,105 holders of record of our Common Stock and our closing stock price was $13.39. 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 the past two years and do not expect to do so in the foreseeable future. Our credit facilities with Bank of Montreal prohibit 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, 2002 to (i) the NASDAQ market composite index ("Market Index") and (ii) 57 active NASDAQ exploration and production companies ("Peer Index"). The graph assumes that a $100 investment was made in the Company's common stock and each index on December 31, 2002, 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 Peer Index 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 stockholders 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
12/31/2003	204.7	149.5	176.7
12/31/2004	212.1	154.3	274.3
12/30/2005	216.8	166.2	423.1
12/29/2006	447.7	182.6	472.0
12/31/2007	404.7	198.0	491.3

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.

Equity Compensation Plan Information: The Equity Compensation Plan table provides information as of December 31, 2007 with respect to shares of the Company's common stock that may be issued under its existing equity compensation plans:

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) (1) (2)**
Equity compensation plans approved by security holders	713	$2.94	793
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	713	$2.94	793

(1) All 793,000 shares may be issued in the form of restricted stock.
(2) Under the current terms of the 2005 Stock Incentive Plan, the maximum number of shares of the Company's common stock that are available for awards under this plan is limited to 10% of the total number of the Company's issued and outstanding shares of common stock, reduced by the number of shares that have been issued or are issuable under the Company's expired 1995 Flexible Incentive Plan.

Unregistered Sales of Equity Securities: As disclosed on the Company's Form 8-K, filed with the SEC on November 21, 2007, the Company entered into an agreement related to the private placement of an aggregate of $55 million of Series C convertible preferred stock with accredited investors.

Issuer Purchases of Equity Securities: We did not reacquire any of our own securities during the fourth quarter of 2007.

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)	**2007(a)**	**2006**	**2005**	**2004**	**2003**
Operating revenues	$93,903	$72,418	$67,000	$57,735	$39,545
Net income	1,340	7,241	13,741	2,797	41
Income available to common stockholders	943	7,241	13,741	2,797	41
Earnings per common share:					
Basic	0.03	0.23	0.48	0.11	0.00
Diluted	0.03	0.22	0.48	0.10	0.00
Cash dividends	n/a	n/a	n/a	n/a	n/a
Net cash provided by operating activities	69,392	24,724	6,260	16,447	15,158
Net cash provided (used) by investing activities	(210,409)	(59,845)	28,293	(39,718)	(36,282)
Net cash provided (used) by financing activities	146,966	32,920	(31,588)	20,208	24,971
Total assets	354,607	143,801	109,536	114,237	84,206
Long-term obligations	120,233	4,054	2,027	31,654	28,909
Stockholders' equity	$174,716	$123,652	$83,281	$65,682	$42,792
Weighted average shares outstanding:					
Basic	33,422	31,916	28,444	26,066	20,781
Diluted	34,470	33,247	28,885	26,971	21,295

n/a - No cash dividends have been paid.
(a) - The growth in several factors listed for 2007 is largely due to the 2007 acquisition of Output Exploration, LLC. See the related discussion in the "Recent Developments" section in Part I, Item 1.

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, the Fort Trinidad field in East 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 primarily by acquiring undeveloped as well as under-developed 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[SM] under the symbol "TXCO."

We currently have six drilling rigs operating on our extensive 700,000-acre position in the Maverick Basin and three in the Midcontinent region. Completions in 2007 included 40 oil and seven gas wells, which included 14 re-entries, while 39 wells spud during the year remained in progress at year-end. The 2008 CAPEX includes funds for participation in 97 wells (35 Glen Rose Porosity, eight to 16 San Miguel Oil Sands, 20 Pena Creek San Miguel, 11 Austin Chalk, 10 Fort Trinidad Glen Rose, six Georgetown, two Pearsall, and one Jurassic), as well as funds for other exploration and development work, steam equipment 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 2007. (For further discussion of this activity, see Item 1 Business, "Principal Areas of 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 available to common stockholders of $0.9 million, or $0.03 per basic share and diluted share, for the year ended December 31, 2007, compared to $7.2 million, or $0.23 per basic share and $0.22 per diluted share, for the prior year. Higher oil and gas sales revenues were partially offset by lower gas gathering revenues. Increases in lease operating expenses, depreciation, depletion and amortization, and general and administrative expenses were partially offset by lower gas gathering operation expenses and the elimination of net mark-to-market losses on derivatives. These factors are discussed in the Results of Operations section.

We continued our ongoing trend of annual reserve growth in 2007 by recording net proved reserve additions of 50.3 Bcfe. Combined with annual production of 8.0 Bcfe, our gross reserve additions for the year were 58.3 Bcfe. Estimated year-end proved oil and gas reserves were 91.8 Bcfe, 121.7% above the 41.4 Bcfe at year-end 2006. We achieved a 731.4% all-source reserve replacement rate in 2007. Positive cash flow provided from operations totaled $69.4 million. Excluding changes in operating assets and liabilities, operating cash flow was $49.3 million, a 42.5% increase from $34.6 million in the prior year primarily due to higher revenue for 2007 due to increased production from drilling coupled with the increase brought on by the Output acquisition. The following table illustrates key features of our continuous development over the four fiscal years presented.

	Year Ended December 31,			
Development:	**2007**	**2006**	**2005**	**2004**
No. of oil wells completed	44	43	25	27
No. of gas wells completed	10	1	6	25
Gas sales (mmcf)	2,125	1,104	2,222	2,975
Gas reserve additions from drilling (mmcf)	7,394	198	5	6,432
Oil sales (mBbl)	974	791	397	321
Oil reserves additions from drilling (mBbl)	719	778	522	1,396
Gas equivalent sales (Bcfe)	8.0	5.9	4.6	4.9
Oil equivalent sales (mBOE)	1,328	975	768	817
Reserve additions (Bcfe)				
Drilling	11.7	4.9	3.2	14.8
Revisions of previous estimates	12.8	3.0	4.3	(0.9)
Purchased in place, net of reserves sold	33.8	-	-	0.5
Total reserves added (Bcfe) ***(1)***	58.3	7.9	7.5	14.4
Reserve replacement rate ***(2)***				
Drill bit	308%	135%	161%	283%
Drill bit plus purchases (all sources)	731%	135%	161%	295%
Non-developed Texas gross acreage leased	807,042	748,320	758,031	491,289
Non-developed Oklahoma & Louisiana acreage leased	47,349	-	-	-
Non-developed Williston Basin acreage leased	-	82,761	83,721	84,654

(1) Make-up of total proved developed reserves at year-end 2007: 54% oil, 46% gas.
(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.

2007 Acquisitions: On April 2, 2007, we closed on the purchase of Output Exploration, LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase was $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, effectively doubled our proved reserves and increased current oil and gas production by nearly two thirds relative to pre-acquisition levels. The core of the Output assets is in the East Texas Fort Trinidad Field and is prospective for the Glen Rose, Buda, Austin Chalk, Eagleford/Woodbine and Bossier formations. Other Output assets acquired include acreage in the Midcontinent and Gulf Coast regions and shallow Gulf Coast waters.

Separately in February 2007, we acquired an interest in primarily shallow horizons under 85,681 acres in an agreement with EnCana. In September 2007, we acquired additional shallow horizons from EnCana under our Comanche, Cage Ranch and other existing leases along with the option to earn Pearsall and deeper horizons. Effective December 1, 2007, we acquired additional interests in our Fort Trinidad area holdings from other working interest holders.

2007 Sales of Certain Interests: During the fourth quarter of 2007, we sold our interests in the Pine Prairie and Doughty fields, which had been acquired as part of the Output acquisition, for approximately $6.0 million in cash.

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 Overthrust, 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 then outstanding Series B 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.

***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 can not 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 2094. However, as shown in the table in Item 2 of this Form 10-K, we expect to realize approximately 60.8% of that production by year-end 2012.

CAPITAL RESOURCES AND LIQUIDITY

Liquidity is a measure of ability to access cash. We primarily need cash 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 can not 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 and preferred 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 current 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

In connection with our acquisition of Output in April 2007, we replaced our credit facility with Guaranty Bank with two new facilities with the Bank of Montreal, as agent. Both of these facilities were amended in July 2007, as described below.

Senior Credit Agreement -- At December 31, 2007, we had a $125 million senior revolving credit facility with the Bank of Montreal, as agent (the "SCA"). The SCA was entered into in April 2007 and expires in April 2011. The SCA was amended on July 25, 2007, decreasing the borrowing base from $60.0 million to $50.0 million and adding a requirement to hedge a portion of TXCO's projected oil and gas production. At the same time, our term loan facility was increased from $80 million to $100 million.

At December 31, 2007, the borrowing base was $47 million, and there were no outstanding borrowings, leaving the unused borrowing base at $47 million. The SCA is secured by a first-priority security interest in TXCO's and certain of its subsidiaries' proved oil and natural gas reserves and in the equity interests of such subsidiaries. In addition, TXCO's obligations under the SCA are guaranteed by such subsidiaries. As of March 13, 2008, the balance outstanding under the SCA was $9.7 million with a weighted average interest rate of 5.01%, while the borrowing base was $50 million with $40.3 million unused.

Loans under the SCA are subject to floating rates of interest based on (1) the total amount outstanding under the SCA in relation to the borrowing base and (2) whether the loan is a LIBOR loan or a base rate loan. LIBOR loans bear interest at the LIBOR rate plus the applicable margin, and base rate loans bear interest at the base rate plus the applicable margin. The applicable margin varies with the ratio of total outstanding to the borrowing base. For base rate loans it ranges from zero to 100 basis points and for LIBOR rate loans it ranges from 150 to 250 basis points.

Under the SCA, we are required to pay a commitment fee on the difference between amounts available under the borrowing base and amounts actually borrowed. The commitment fee is (1) 0.375%, so long as the ratio of amounts outstanding under the SCA to the borrowing base is less than 30%, and (2) 0.50%, in the event such ratio is 30% or greater. Borrowings under the SCA may be repaid and reborrowed from time to time without penalty.

Term Loan Agreement -- At December 31, 2007, we had a $100 million five-year term loan facility, all of which was outstanding, with Bank of Montreal, as agent, (the "TLA") and certain other financial institutions party thereto with a then-current interest rate of 9.875%. The TLA was amended on July 25, 2007, increasing the principal amount from $80 to $100 million and extending the prepayment penalty date to July 25, 2008. At March 13, 2008, the interest rate on the TLA stood at 7.625%.

Loans under the TLA are subject to floating rates of interest equal to, at our option, the LIBOR rate plus 4.50% or the base rate plus 3.50%. The "LIBOR rate" and the base rate are calculated in the same manner as under the SCA.

Borrowings under the TLA may be repaid (but not reborrowed) subject to a prepayment premium equal to (i) 1.0%, if prepaid prior to July 25, 2008 and (ii) 0.0%, thereafter. Additionally, no prepayments are permitted if the ratio of the total amount outstanding under the SCA to the borrowing base thereunder exceeds 75% or if any default exists under the SCA. Both the SCA and the TLA contain certain restrictive covenants which, among other things, limit the incurrence of additional debt, investments, liens, dividends, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, derivative contracts, sale leasebacks and other matters customarily restricted in such agreements. The SCA requires TXCO and its subsidiaries to not exceed a maximum consolidated leverage ratio of 3.00 to 1.00, while the amended TLA requires TXCO and its subsidiaries to not exceed a maximum consolidated leverage ratio of 3.50 to 1.00. Both the SCA and the TLA require TXCO and its subsidiaries to meet a minimum current assets to current liabilities ratio of 1.00 to 1.00 (after considering the unused portion of the SCA), a minimum interest coverage ratio of 2.00 to 1.00 and a minimum net present value to consolidated total debt ratio of 1.50 to 1.00. The ratios are calculated on a quarterly basis. Both agreements also contain customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate outstanding term loans may require Bank of Montreal, as agent, to declare all amounts outstanding under the SCA and TLA to be immediately due and payable.

Preferred Stock Issuance: In November 2007, we issued 55,000 shares of Series C preferred stock, which is currently convertible into approximately 3.8 million common shares, in a private placement raising approximately $52.8 million net of expenses. Holders of the Preferred are entitled to receive dividends, payable quarterly in cash or the Company's common stock, at the rate of 6.5% per annum. The Preferred is described more fully in Note F to the consolidated financial statements

Additionally, subsequent to year end we issued 20,000 shares of Series E preferred stock, which is currently convertible into approximately 1.15 million common shares, in a private placement raising approximately $17.8 million net of expenses. In addition, the buyers of the Series C preferred stock exchanged their 55,000 issued and outstanding shares of our Series C preferred stock for 55,000 shares of Series D preferred stock. The Series D preferred stock provides for the same conversion price as was on the Series C. See Note N for discussion of Series D and Series E preferred stock issued during early 2008.

2008 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 2008. 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 2008 capital budget with an initial range of $100 million to $110 million -- our largest ever, targeting 97 gross wells, as well as certain leasehold acquisitions. We expect to fund our CAPEX program from cash provided by the recent preferred stock issuances, internal cash flow and our credit facilities.

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 2008 wells:

	Typical Gross Well Costs	
(In thousands)	**Dry Hole**	**Completed**
Glen Rose oil porosity zone horizontal well	$1,000	$1,450
Glen Rose shoal horizontal gas well -- Fort Trinidad	1,000	2,500
Glen Rose vertical reef well	450	750
Georgetown horizontal oil well	550	1,000
Pearsall/Sligo horizontal gas well	3,000	4,500
San Miguel waterflood oil well	150	400
San Miguel oil sands heavy oil well - vertical	300	500
San Miguel oil sands heavy oil well - horizontal	300	1,200

Maverick Basin Activity**:** The Glen Rose Porosity oil play (50-100 percent WI) will continue to receive the largest share of our CAPEX, $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

Output Properties: Capital expenditures are expected to be approximately $19.9 million in 2008 for the Fort Trinidad and Midcontinent areas, which were acquired from Output during 2007.

Marfa Basin Activity: In the Marfa Basin (50% WI), which is prospective for the Barnett and Woodford shales, the Company has allocated approximately $1.5 million for a seismic acquisition program or one new horizontal well.

Williston Basin Activity: We participated in the drilling of one new well and two reentries in the Red River "B" in the Williston Basin during 2007. No additional funds are included in our 2008 CAPEX for this area. Most of our undeveloped leases in North Dakota were allowed to expire during 2007.

Sources and Uses of Cash

Net cash provided by operating activities increased over the three-year period presented from $6.3 million in 2005 to $69.4 million in 2007. The 2007 figure included a $16.7 million year end accrual for property acquisition costs related to a transaction with a December 1, 2007 effective date. Fiscal 2005 was impacted negatively by a one-time cash outlay 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)	**2007**	**2006**	**2005**
Net cash provided by operating activities	$69,392	$24,724	$6,260
Adjustments:			
Accrued property acquisition cost	(16,650)	-	-
Payment to terminate derivative treated as an investment	-	-	7,564
Payment to terminate cash flow hedge	-	-	2,356
Federal income tax, current & deferred	843	2,661	3,923
Adjusted cash provided by operating activities	$53,585	$27,385	$20,103
Change from prior year	+26,200	+7,282	+3,510
% Change from prior year	+95.7%	+36.2%	+21.2%

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, preferred stock in 2007, and the 2005 Asset Sale.

Adjusted Cash Provided

For the Years Ended December 31,

(In thousands)	**2007**	**2006**	**2005**
Beginning cash reserves	$3,882	$6,083	$3,118
Net cash provided by operating activities	69,392	24,724	6,260
Internally generated funds	73,274	30,807	9,378
Proceeds from sale of assets	6,001	23	78,002
Issuance of common and/or preferred stock, net of expenses	53,120	30,565	2,915
Proceeds from sale of upper call option	17,852	-	-
Proceeds from bank credit facilities	168,500	13,450	15,001
Proceeds from installment obligations	710	494	356
Total other sources of cash	246,183	44,532	96,274
Adjusted Cash Provided, from all sources	$319,457	$75,339	$105,652
Change from prior year	+244,118	-30,313	+44,928
% Change from prior year	+324.0%	-28.7%	+74.0%

We applied these funds as indicated in the following table:

Uses of Cash

For the Years Ended December 31,

(In thousands)	**2007**	**2006**	**2005**
Drilling and completion costs, 3-D seismic, and leasehold acquisitions	$117,311	$52,927	$49,672
Purchase of subsidiary	95,994	-	-
Other property and equipment	3,105	6,941	37
Sub-total	216,410	59,868	49,709
Debt principal payments, excluding interest	71,428	11,589	33,860
Purchase of lower call option	21,569	-	-
Purchase of treasury shares	219	-	-
Redemption of Series B preferred stock	-	-	16,000
Cash Utilized	$309,626	$71,457	$99,569

Borrowings on the bank credit facilities were used to purchase Output Exploration, LLC. Proceeds from the sale of Series C preferred stock were used to pay down debt and to provide additional liquidity in order to complement funding of 2008 CAPEX. Proceeds from the 2005 Asset Sale were used to redeem the Series B preferred stock and repay essentially all then-outstanding debt.

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

(In thousands, except ratios)	**2007**	**2006**	**2005**
Current assets	$35,746	$18,369	$17,047
Less: Current liabilities	59,658	16,095	24,228
Net working capital (deficit)	$(23,912)	$2,274	$ (7,181)
Current ratio	0.60	1.14	0.70

2005 through 2007 Sales and Acquisitions: Please see the discussion regarding the acquisitions and sales included in the Overview section of this MD&A.

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:	**2007 vs. 2006**	**2006 vs. 2005**	**2005 vs. 2004**
Oil and gas revenues	+44.6	+46.7	+27.7
Gas gathering revenues	-24.6	-44.2	+3.2
Gas gathering expenses	-18.4	-42.6	+11.9
Lease operations expense	+94.6	+12.0	+18.5
Impairment & abandonments	+15.1	+22.4	-40.3
Depreciation, depletion & amortization	+51.9	+89.3	+27.9
Net income	-81.5	-47.3	+391.3
Income available to common stockholders	-87.0	-47.3	+391.3
Basic income per common share	-87.0	-52.1	+336.4

Percentage Change in Selected Operating Items:	**2007 vs. 2006**	**2006 vs. 2005**	**2005 vs. 2004**
Oil sales volumes	+23.1	+99.2	+23.6
Gas sales volumes	+92.5	-50.3	-25.3
Combined sales volumes	+36.2	+27.1	-6.1
Net residue and NGL sales volumes	-26.6	-39.1	-24.1
Oil average sales price per Bbl, excluding hedging impact	+13.7	+15.4	+40.0
Gas average sales price per mcf, excluding hedging impact	+1.2	-6.2	+28.3
Residue & NGL sales price per mmBtu	+2.7	-11.5	+35.7

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

Gas Gathering Results: *($ in thousands)*	**2007**	**2006**	**2005**
Revenues:			
Residue gas sales	$8,182	$13,039	$23,330
Natural gas liquids sales	2,898	2,053	4,652
Transportation and other revenue	878	761	448
Total gas gathering revenues	11,958	15,853	28,430
Expense:			
Third-party gas purchases	11,945	15,223	27,112
Transportation and marketing expenses	228	89	278
Direct operating costs	1,084	943	922
Total gas gathering operations expense	13,257	16,255	28,312
Gross margin	$(1,299)	$ (402)	$118

2007 Compared to 2006

Revenues

Total revenues increased by $21.5 million. Natural gas sales volumes increased by 1.021 bcf while oil sales volumes increased by 182,969 BO, resulting in a combined increase of 2.1 bcfe or 353,130 BOE. Average daily net gas sales were 5.8 mmcf, a 92.5 % increase. The increase in natural gas sales volumes was primarily due to the acquisition of Output, partially offset by normal declines experienced in maturing gas wells. Average daily net oil production rates were 2,670 BO, a 23.2% increase. The increase in oil sales volumes reflects higher Glen Rose Porosity production.

On an equivalent-unit basis, prices averaged 8.3% higher. Crude oil prices averaged 13.7% higher while natural gas prices were up 1.2%. Higher average prices had a $8.5 million positive impact on revenues in 2007. Increased sales volumes had a $18.8 million positive impact on revenues for the year. Commodity prices have been, and continue to be, volatile. During 2007, realized gas prices ranged from a high of $8.85 per mcf in October to a low of $6.20 per mcf in January, while realized crude oil prices ranged from a high of $93.17 in November to a low of $51.75 in January.

Lease Operations

Lease operating expense increased $6.9 million, or 94.6%. This increase was primarily due to the Output acquisition and the addition of 40 new oil wells and seven new gas wells during 2007. 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 $0.66 to $2.33.

Gas Gathering

Gas gathering revenues decreased 24.6%, while related operating expenses decreased 18.4%. These decreases are consistent with the decreased gas throughput for the gathering system compared to the prior period. See the "Gas Gathering Results" table above.

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 15.1% due to recognizing the impairment on certain oil and gas properties.

Depreciation, Depletion and Amortization

DD&A increased by $12.4 million, or 51.9%, consistent with the number of acquired and newly drilled producing wells being depleted. The increase in depreciation was due to increased investments in other equipment including computer and equipment additions (including drilling rigs). The increase in amortization primarily reflects the acquisition of Output.

General and Administrative

G&A costs increased 65.2% and were 12.9% of revenues. This compares to 2006 when G&A expenses were 10.1% of revenues. The higher level of absolute-dollar costs reflects our higher sustained level of operations and the Output acquisition. The increase also reflects higher salaries, benefits, and office-related expenses for a full year related to 6 employees hired during 2006, and a partial year for an additional 10 employees hired during 2007.

($ in thousands)	**2007**	**2006**	**% change**
Non-cash, stock compensation expense	$1,799	$1,207	49.0
Non-cash, value of ORRI	1,025	-	n/m
Costs related to assimilating Output acquisition	525	-	n/m
Other G&A expense	8,709	6,091	43.0
Total G&A expense	$12,058	$7,298	65.2

n/m - not meaningful since prior year was zero

During 2007, we incurred some non-recurring G&A costs in the following forms. These costs included the cost of integrating the Output acquisition into our operations (see table above). These costs include salaries during a transition period paid to Output employees and consultants, and moving the Output office. Also of a non-recurring nature, was a $1.0 million charge for the value of the 1% overriding royalty interest ("ORRI") in conjunction with the Output acquisition that will be assigned, under a 1996 agreement, with our president. No comparable charge was recorded in the prior year.

We expect G&A costs to return to our historical levels as a percentage of revenues in 2008.

Interest Income / Expense

The increase in interest expense reflects higher average balances on our credit facility related to our April 2007 acquisition of Output.

Net Income / Earnings Per Share

We reported net income available to common stockholders of $0.9 million, $0.03 per basic and diluted share, compared to a net income of $7.2 million, $0.23 per basic share and $0.22 per diluted share for the prior year.

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 reflected the accretion of deferred losses related to gas hedges that were terminated in 2005. We expensed 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 was primarily due to the addition of 43 new oil wells and one new gas well during 2006. The increase reflected 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 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 were 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 at the beginning of this section. 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. 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 represented 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 reflected higher salaries, benefits, and office-related expenses for a full year related to two employees hired 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.

Gain / Loss 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 $7.2 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.

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES AND COMMITMENTS

The following is a summary of our future payments on obligations as of December 31, 2007.

	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)	$ -	$ -	$100,000	$ -	$100,000
Operating lease obligations	776	1,506	1,248	635	4,165
Notes payable	399	-	-	-	399
Total Contractual Cash Obligations	$1,175	$1,506	$101,248	$635	$104,564

(1) excluding interest

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 there from 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

Significant management judgment is required to determine the provisions for income taxes and to determine the provisions for income taxes and to determine whether deferred tax assets will be realized in full or in part. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. When it is more likely than not that all or some portion of specific deferred income tax assets will not be realized, a valuation allowance must be established for the amount of deferred income tax assets that are determined not to be realizable.

Additionally, despite our belief that our tax return positions are consistent with applicable tax law, we believe that certain positions may be challenged by taxing authorities. Settlement of any challenge can result in no change, a complete disallowance, or some partial adjustment reached through negotiations.

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." We adopted FIN 48 effective on January 1, 2007. FIN 48 clarified the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. FIN 48 prescribes how a company should recognize, measure, present and disclose uncertain tax positions that the company has taken or expects to take in its income tax returns. FIN 48 requires that only income tax benefits that meet the "more likely than not" recognition threshold be recognized or continue to be recognized on its effective date.

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. In prior years, we had 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 were 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 September 2006, the FASB issued SFAS No. 157, "Fair Value Measurement" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The standard applies whenever other standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. In February 2008, the FASB granted a one-year deferral of the effective date of this statement as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and goodwill impairment). SFAS No. 157 is effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. We have completed our initial evaluation of the impact of SFAS No. 157 as it relates to our financial assets and liabilities and determined that its adoption is not expected to have a material impact on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"). SFAS No. 159 allows entities the option to measure eligible financial instruments at fair value as of specified dates. Such election, which may be applied on an instrument by instrument basis, is typically irrevocable once elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, and early application is allowed under certain circumstances. We do not expect the adoption of SFAS No. 159 to have a significant impact on our consolidated financial position, results of operations or liquidity.

In December 2007, Financial Accounting Standards Board ("FASB") issued SFAS No. 141(R), "Business Combinations" ("SFAS 141(R)"), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS 141(R) will have an impact on accounting for business combinations once adopted, but the effect is dependent upon acquisitions at that time.

In December 2007, FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements -- an amendment of Accounting Research Bulletin No. 51" ("SFAS 160"), which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, changes in a parent's ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We do not currently have non-controlling interests in any of our subsidiaries.

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. We enter into financial price hedges from time to time covering a portion of our monthly volumes. The amount and timing are generally determined by requirements under our credit facilities. Our current hedges are described in the table below. A 10% fluctuation in the price received for oil and gas production would have an approximate $8.2 million impact on our annual revenues based on 2007 sales volumes.

Derivative Contracts at Year End:

Transaction Date	Transaction Type	Beginning	Ending	Average Floor or Fixed Price Per Unit	Average Ceiling Price Per Unit	Volumes Per Month
Natural Gas - mcf (1):						
08-12/07	Collar	01/01/2008	12/31/2008	$6.50	$10.22	97,000
08-12/07	Collar	01/01/2009	12/31/2009	$6.50	$11.58	80,000
08-12/07	Collar	01/01/2010	06/30/2010	$6.50	$11.65	70,000
12/07	Collar	07/01/2010	12/31/2010	$6.50	$11.13	67,000
Crude Oil - Bbl (2):						
06/05	Fixed Price	11/01/2006	04/30/2007	$56.70	n/a	15,000
08-12/07	Collar	01/01/2008	12/31/2008	$67.31	$81.05	26,000
08-12/07	Collar	01/01/2009	12/31/2009	$66.18	$76.05	17,000
08-12/07	Collar	01/01/2010	06/30/2010	$66.43	$76.74	14,000
12/07	Collar	07/01/2010	12/31/2010	$75.00	$99.00	12,500

(1) These natural gas hedges were entered into on a thousand cubic foot (mcf) delivered price basis, using the Houston Ship Channel Index, with settlement for each calendar month occurring following the expiration date, as determined by the contracts.
(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.

The Consolidated Balance Sheet at December 31, 2007, includes a liability for derivative mark-to-market losses of $4.7 million as "Accrued derivative obligation - current," as well as a $0.5 million liability for "Derivative settlements payable" both in the "Current Liabilities" section, and an additional $4.0 million liability for long-term derivative mark-to-market losses as "Accrued derivative obligation - long-term" in the "Long-Term Liabilities" section. A derivative settlement loss of $3.0 million was recognized as a reduction to "Oil and Gas Revenues" on the Consolidated Statement of Operations in 2007.

Call Spread Transactions: In connection with the offer and sale of the preferred stock, Series C, we entered into convertible preferred stock hedge transactions, or "call spread" transactions, with one of the buyers of the stock (the "Counterparty"). These transactions are intended to reduce the potential dilution upon conversion of the preferred stock, Series C, if the market value per share of our common stock at the time of exercise is greater than approximately 120% of the issue price (which corresponds to the initial conversion price of the preferred stock, Series C). These transactions include a purchased call option and a sold call option. The purchased call option covers approximately the same number of shares of our common stock, par value $0.01 per share, which, under most circumstances, represents the maximum number of shares of common stock underlying the preferred stock, Series C. The sold call option has an exercise price of 150% of the issue price and is expected to result in some dilution should the price of our common stock exceed this exercise price.

Interest Rate Risk**:** We have borrowed funds under our Credit Facilities with the Bank of Montreal, as agent, with interest based on LIBOR rates plus an applicable margin. At March 13, 2008, we had $109.7 million in total borrowings under the Facilities, with an average interest rate of 7.394%. At our current borrowing level, an annualized 10% fluctuation in interest charged on the floating rate balance at March 13, 2008, would have $0.8 million impact on our annual net income, before taxes.

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 2007, 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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as it is defined in Exchange Act Rules 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles ("GAAP"). Under the supervision and with the participation of our management, including the CEO and the CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control -- Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our internal control over financial reporting 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 our 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 our 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 conducting our evaluation of the effectiveness of our internal control over financial reporting, we excluded the acquisition of Output Exploration, LLC in April 2007 due to its size and complexity. Collectively, this acquisition constituted approximately 36.5% of our total consolidated assets as of December 31, 2007, and approximately 19.9% of our total consolidated revenues for the year then ended. The exclusion was in accordance with Securities and Exchange Commission guidance that an assessment of a recently acquired business may be omitted in management's report on internal controls over financial reporting, provided the acquisition took place within twelve months of management's evaluation.

Based on our evaluation under the framework in *Internal Control -- Integrated Framework,* our management believes that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by Akin, Doherty, Klein & Feuge, P.C., an independent registered public accounting firm, as stated in their report that follows.

James E. Sigmon	P. Mark Stark
Chairman, President and Chief Executive Officer	Vice President and Chief Financial Officer

Attestation Report Of Independent Registered Public Accounting Firm
On Internal Control Over Financial Reporting

To The Board of Directors And Stockholders of
TXCO Resources Inc. and Subsidiaries
San Antonio, Texas

We have audited TXCO Resources Inc. and subsidiaries (the Company) internal control over financial reporting as of December 31, 2007, 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 included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

As indicated in the accompanying *Management's Report on Internal Control Over Financial Reporting*, in conducting management's assessment of and conclusion on the effectiveness of internal controls over financial reporting, management has excluded its wholly owned subsidiary, Output Exploration, LLC, which was acquired on April 2, 2007. Output Exploration, LLC represented approximately 36.5% of TXCO Resources Inc.'s total assets and approximately 19.9% of its total revenues at December 31, 2007. Management did not assess the effectiveness of internal controls over financial reporting at this subsidiary due to the transaction size and complexity and timing of the acquisition. Our audit of internal controls over financial reporting of TXCO Resources Inc. did not include an evaluation of the internal control over financial reporting of Output Exploration, LLC.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007 and 2006 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007, of TXCO Resources Inc. and subsidiaries and our report dated March 15, 2008, expressed an unqualified opinion thereon.

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

San Antonio, Texas
March 15, 2008

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item relating to our directors and nominees, executive officers, compliance with Section 16(a) of the Exchange Act and certain corporate governance matters is included under the captions "Proposal I -- Election of Directors," "Executive Officers" and " Section 16(a) Beneficial Ownership Reporting Compliance, "Corporate Governance," and "Other Matters" in our Proxy Statement for the 2008 Annual Meeting of Stockholders ("Proxy Statement") 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, 2007.

Code of Business Conduct: Pursuant to Nasdaq Rule 4350(n), we have adopted a Code of Business Conduct and Ethics ("Code") that applies to all of our employees, officers and directors. This Code also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access the Code on the "Governance" section of our website at www.txco.com. You may obtain a printed copy of the Code by submitting a written request to our Corporate Secretary at TXCO Resources Inc., 777 E. Sonterra Blvd., Suite 350, San Antonio, Texas 78258.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is included in the "Director Compensation," "Executive Compensation," "Compensation Committee Report," and "Compensation Committee Interlocks and Inside-participation" sections in the Proxy Statement 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 Item is included in the Proxy Statement under the heading "Security Ownership of Directors and Executive Officers" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this Item is included in the Proxy Statement under the heading "Certain Relationships and Related Persons Transactions" and "Director Independence," and is incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is included in the Proxy Statement under the heading "Auditor Independence" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

(1) Consolidated Financial Statements:
Report of Independent Registered Public Accounting Firm.
Consolidated Balance Sheets, December 31, 2007 and December 31, 2006.
Consolidated Statements of Operations, Years Ended December 31, 2007, 2006 and 2005.
Consolidated Statements of Stockholders' Equity, Years Ended December 31, 2007, 2006 and 2005.
Consolidated Statements of Cash Flows, Years Ended December 31, 2007, 2006 and 2005.
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
2.1	Agreement and Plan of Merger, dated February 20, 2007, by and among Registrant, Output Acquisition Corp., and Output Exploration, LLC		8-K	2.1	02/26/2007
2.2	Amendment No. 1 to Agreement and Plan of Merger listed in Exhibit 2.1 above		8-K	2.1	02/26/2007
3.1	Restated Certificate of Incorporation of Registrant		10-Q	3.1	08/09/2007
3.2	Amended and Restated Bylaws		10-Q	3.1	05/10/2007
3.3	Certificate of Designations, Preferences and Rights of Series C Convertible Preferred Stock of Registrant		8-K	3.1	11/21/2007
4.1	Specimen common stock certificate		S-1	4.1	04/28/06
4.2	Credit Agreement between Registrant and Guaranty Bank, FSB, dated June 30, 2004.		10-Q	4	08/09/2004
4.3	First Amendment to Credit Agreement between Registrant and Guaranty Bank, FSB, effective as of March 24, 2005		10-Q	4.1	05/10/2005
4.4	Waiver and Second Amendment to Credit Agreement between Registrant and Guaranty Bank, FSB, effective August 23, 2005		10-Q	4.1	11/09/2005
4.5	Third Amendment to Credit Agreement between Registrant and Guaranty Bank, FSB, effective as of December 15, 2005		10-K	3.1	03/16/2006
4.6	Fourth Amendment to Credit Agreement among Registrant, TXCO Energy Corp. and Guaranty Bank, FSB, effective as of November 1, 2006		10-K	3.1	03/16/2007
4.7	Registration Rights Agreement, dated November 20, 2007, among Registrant and the parties listed therein		8-K/A	4.1	12/3/2007
4.8	Rights Agreement, dated June 29, 2000, between Registrant and Fleet National Bank		8-K	4.1	7/7/2000

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
4.9	Agreement of Substitution and Amendment of Common Shares Rights Agreement dated November 1, 2007, between Registrant and American Stock Transfer and Trust Company		8-K/A	4.2	12/3/2007
4.10	Amendment No. 2 to Rights Agreement, dated November 19, 2007, between Registrant and American Stock Transfer and Trust Company.		8-K/A	4.3	12/3/2007
10.1*	Employment Agreement between 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*	Form of Amended and Restated Change of Control Letter Agreement		8-K	10.1	12/17/2004
10.7*	Amended and Restated 2005 Stock Incentive Plan	X			
10.8	Purchase and Sale Agreement, between Registrant and EnCana Oil & Gas (USA) Inc., effective as of September 1, 2005.		10-Q	10.1	11/09/2005
10.9	Partial Assignment of Oil, Gas and Mineral Leases - Northern Lands between Registrant and EnCana Oil & Gas (USA) Inc., effective as of September 1, 2005.		10-Q	10.3	11/09/2005
10.10	Assignment - Comanche Ranch between Registrant and CMR Energy, L. P., effective as of September 1, 2005.		10-Q	10.4	11/09/2005
10.11	Assignment - Glen Rose Rights between Registrant and CMR Energy, L. P., effective as of September 1, 2005.		10-Q	10.5	11/09/2005
10.12	Seismic Data License Agreement between Registrant and EnCana Oil & Gas (USA) Inc., effective as of September 1, 2005.		10-Q	10.7	11/09/2005
10.13	Transition Services Agreement between Registrant and EnCana Oil & Gas (USA) Inc., effective as of September 1, 2005.		10-Q	10.8	11/09/2005
10.14	Partial Release of Liens and Security Interests between Registrant and EnCana Oil & Gas (USA) Inc., effective as of September 1, 2005.		10-Q	10.9	11/09/2005
10.15	Operating Agreement between Registrant and EnCana Oil & Gas (USA) Inc., effective as of September 1, 2005.		10-Q	10.10	11/09/2005
10.16	Release and Reassignment of Net Profits Interest between Registrant and Arrow River Energy L. P., effective as of September 1, 2005.		10-Q	10.11	11/09/2005
10.17*	Form of Restricted Stock Award		10-Q	10.2	05/10/2006
10.18	Purchase Agreement, dated March 30, 2006, between Registrant and several investors named therein		8-K	10.1	04/05/2006
10.19	Registration Rights Agreement, dated April 4, 2006, between Registrant and several investors named therein		8-K	10.1	04/05/2006
10.20	Amended and Restated Credit Agreement, dated April 2, 2007, among Registrant, as Borrower, Output Acquisition Corp., as a Guarantor, the other Guarantors described therein, Bank of Montreal, as Lender and Administrative Agent for the Lenders, the other Lenders party thereto, and BMO Capital Markets Corp., as Arranger		8-K	10.1	04/05/2007

Exhibit Number	Exhibit Description	Filed Herewith	Form	Exhibit	Filing Date
10.21	First Amendment to the Amended and Restated Credit Agreement, dated July 25, 2007, among the same parties listed in Exhibit 10.22 above		8-K	10.2	07/27/2007
10.22	Amended and Restated Term Loan Agreement, dated July 25, 2007, among the same parties listed in Exhibit 10.22 above		8-K	10.1	07/27/2007
10.23	Senior Secured Second Lien Term Loan Facility $20,000,000 Increased Facility Amount Supplemental Commitment Letter, among the same parties listed in Exhibit 10.22 above		8-K	10.1	07/25/2007
10.24	Securities Purchase Agreement, dated November 20, 2007, among Registrant and the parties listed therein		8-K/A	10.1	12/3/2007
10.25	Upper Call Option Transaction, dated November 20, 2007, between Registrant and the investor named therein		8-K	10.2	11/21/2007
10.26	Lower Call Option Transaction, dated November 20, 2007, between Registrant and the investor named therein		8-K	10.3	11/21/2007
21	Subsidiaries of the Registrant at December 31, 2007	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.

TXCO RESOURCES INC.
Registrant

March 17, 2008

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, CEO and Chairman of the Board (Principal Executive Officer)	March 17, 2008
/s/ Alan L. Edgar Alan L. Edgar	Director	March 17, 2008
/s/ Dennis B. Fitzpatrick Dennis B. Fitzpatrick	Director	March 17, 2008
/s/ Robert L. Foree, Jr. Robert L. Foree, Jr.	Director	March 17, 2008
/s/ James L. Hewitt James L. Hewitt	Director	March 17, 2008
/s/ Jon Michael Muckleroy J. Michael Muckleroy	Director	March 17, 2008
/s/ Michael J. Pint Michael J. Pint	Director	March 17, 2008
/s/ P. Mark Stark P. Mark Stark	Chief Financial Officer Vice-President-Finance (Principal Financial and Accounting Officer)	March 17, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
TXCO Resources Inc. and Subsidiaries
San Antonio, Texas

We have audited the consolidated balance sheets of TXCO Resources Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of TXCO Resources Inc. and subsidiaries as of December 31, 2007 and 2006, and the consolidated results of their operations and cash flows for each of the three years in the period ended December 31, 2007, 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 TXCO Resources Inc. and subsidiaries' internal control over financial reporting as of December 31, 2007 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 15, 2008 expressed an unqualified opinion thereon.

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

San Antonio, Texas
March 15, 2008

TXCO RESOURCES INC.
Consolidated Balance Sheets

(in thousands)	December 31 2007	2006
Assets		
Current Assets		
Cash and equivalents	**$9,831**	$3,882
Accounts receivable:		
Joint interest owners	**4,167**	3,321
Oil and gas sales	**13,785**	5,811
Federal income tax	**4,974**	4,468
Prepaid expenses and other	**2,989**	887
Total Current Assets	**35,746**	18,369
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	**314,941**	119,574
Other Assets		
Deferred tax asset	**-**	5,310
Deferred financing fees	**2,613**	60
Other assets	**1,307**	488
Total Other Assets	**3,920**	5,858
Total Assets	**$354,607**	$143,801

See notes to audited consolidated financial statements.

TXCO RESOURCES INC.
Consolidated Balance Sheets

(in thousands, except shares and per share amounts)	December 31 2007	2006
Liabilities And Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	**$11,345**	$7,969
Other payables and accrued liabilities	**39,916**	6,433
Undistributed revenue	**2,401**	1,035
Notes payable	**399**	267
Derivative settlements payable	**475**	70
Preferred dividends payable	**397**	-
Accrued derivative obligation - short-term	**4,725**	321
Total Current Liabilities	**59,658**	16,095
Long-Term Liabilities		
Long-term debt	**100,000**	2,351
Deferred income taxes	**12,007**	-
Accrued derivative obligation - long-term	**3,993**	-
Asset retirement obligation	**4,233**	1,703
Total Long-Term Liabilities	**120,233**	4,054
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		
Series C, 55,000 shares issued and outstanding	**1**	-
Common stock, par value $0.01 per share; authorized		
100,000,000 shares, issued 34,269,038 and 33,290,698 shares, and outstanding 34,150,619 and 33,190,898	**343**	333
Additional paid-in capital	**177,030**	122,108
Retained earnings	**3,561**	2,619
Accumulated other comprehensive loss, net of tax	**(5,754)**	(1,162)
Less treasury stock, at cost, 118,419 shares and 99,800 shares	**(465)**	(246)
Total Stockholders' Equity	**174,716**	123,652
Total Liabilities and Stockholders' Equity	**$354,607**	$143,801

See notes to audited consolidated financial statements.

TXCO RESOURCES INC.
Consolidated Statements of Operations

	Years Ended December 31		
(in thousands, except earnings per share data)	**2007**	**2006**	**2005**
Revenues			
Oil and gas sales	**$81,753**	$56,520	$38,533
Gas gathering operations	**11,958**	15,853	28,430
Other operating income	**195**	45	37
Total Revenues	**93,906**	72,418	67,000
Costs and Expenses			
Lease operations	**14,105**	7,248	6,470
Production taxes	**4,672**	2,551	2,180
Exploration expenses	**1,222**	2,968	3,266
Impairment and abandonments	**1,983**	1,722	1,406
Gas gathering operations	**13,257**	16,255	28,312
Depreciation, depletion and amortization	**36,202**	23,840	12,597
General and administrative	**12,058**	7,298	5,439
Total Costs and Expenses	**83,499**	61,882	59,670
Income from Operations	**10,407**	10,536	7,330
Other Income (Expense)			
Interest income	**329**	550	89
Interest expense	**(9,686)**	(269)	(2,920)
Loan fee amortization	**(554)**	(216)	(132)
Derivative mark-to-market gain (loss)	**-**	1,995	(2,128)
Derivative settlements loss	**-**	(2,686)	(9,115)
Gain (loss) on sale of assets	**1**	(8)	24,540
Total Other Income (Expense), Net	**(9,910)**	(634)	10,334
Income before income taxes	**497**	9,902	17,664
Income tax expense (benefit) -- current	**(5,301)**	1,232	4,851
deferred	**4,458**	1,429	(928)
Net Income	**1,340**	7,241	13,741
Preferred dividends	**397**	-	-
Net Income Available to Common Stockholders	**$943**	$7,241	$13,741
Earnings Per Share:			
Basic	**$0.03**	$0.23	$0.48
Diluted	**$0.03**	$0.22	$0.48
Weighted average number of common shares outstanding:			
Basic	**33,422**	31,916	28,444
Diluted	**34,740**	33,247	28,885

See notes to audited consolidated financial statements.

TXCO RESOURCES INC.
Consolidated Statements of Stockholders' Equity

(in thousands)	Common Stock Shares	Common Stock Amount	Preferred Stock Shares	Preferred Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Treasury Stock	Total
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	-	-	30,431	-	-	-	30,462
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
Stock grants, net of forfeitures	327	3	-	-	(3)	-	-	-	-
Common stock options & warrants exercised	312	3	-	-	89	-	-	-	92
Issuance of common stock - net of expenses of $19	339	4	-	-	3,978	-	-	-	3,982
Issuance of Series C preferred - net of expenses of $2,223	-	-	55	1	52,777	-	-	-	52,778
Call spread options, net	-	-	-	-	(3,717)	-	-	-	(3,717)
Non-cash stock compensation	-	-	-	-	1,798	-	-	-	1,798
Preferred stock dividends	-	-	-	-	-	(398)	-	-	(398)
Purchase of treasury stock	-	-	-	-	-	-	-	(219)	(219)
Comprehensive income:									
Net income for the year	-	-	-	-	-	1,340	-	-	1,340
Deferred hedge loss - net of $2,281 in tax benefit	-	-	-	-	-	-	(4,592)	-	(4,592)
Total comprehensive income									(3,252)
Balance at December 31, 2007	34,269	$343	55	$1	$177,030	$3,561	$(5,754)	$(465)	$174,716

See notes to audited consolidated financial statements.

TXCO RESOURCES INC.

Consolidated Statements of Cash Flows

(in thousands)	Years Ended December 31 **2007**	2006	**2005**
Operating Activities			
Net income	**$1,340**	$7,241	$13,741
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**36,756**	24,056	12,597
Impairments, abandonments and dry hole costs	**2,436**	1,722	1,406
(Gain) loss on sale of assets	**(1)**	8	(24,540)
Deferred tax expense (benefit)	**4,458**	1,560	(928)
Non-cash interest expense - redeemable preferred stock	**-**	-	684
Non-cash compensation expense	**2,824**	1,207	-
Non-cash derivative mark-to market (gain) loss	**-**	(1,995)	2,128
Non-cash change in components of OCI	**1,524**	806	-
Payment to terminate cash flow hedge	**-**	-	(2,356)
Changes in operating assets and liabilities:			
Receivables	**(8,820)**	213	(984)
Prepaid expenses and other	**(6,027)**	747	(469)
Accounts payable and accrued expenses	**35,590**	(2,342)	44
Current income taxes (receivable) payable	**(688)**	(8,499)	4,937
Net cash provided by operating activities	**69,392**	24,724	6,260
Investing Activities			
Development and purchases of oil and gas properties	**(117,311)**	(52,927)	(49,672)
Purchase of subsidiary	**(95,994)**	-	-
Purchase of other equipment	**(3,105)**	(6,941)	(37)
Proceeds from sale of oil and gas properties and other assets	**6,001**	23	78,002
Net cash provided (used) by investing activities	**(210,409)**	(59,845)	28,293
Financing Activities			
Proceeds from bank credit facility	**168,500**	13,450	15,001
Payments on bank credit facility	**(70,851)**	(11,100)	(32,099)
Payments on installment and other obligations	**(577)**	(489)	(1,761)
Proceeds from installment and other obligations	**710**	494	356
Issuance of preferred stock, net of expenses	**52,777**	-	-
Purchase of lower call option	**(21,569)**	-	-
Proceeds from sale of upper call option	**17,852**	-	-
Redemption of preferred stock	**-**	-	(16,000)
Purchase of treasury shares	**(219)**	-	-
Proceeds from issuance of common stock, net of expenses	**343**	30,565	2,915
Net cash provided (used) by financing activities	**146,966**	32,920	(31,588)
Change in Cash and Equivalents	**5,949**	(2,201)	2,965
Cash and Equivalents at Beginning of Year	**3,882**	6,083	3,118
Cash and Equivalents at End of Year	**$9,831**	$3,882	$6,083
Supplemental Disclosures:			
Cash paid for interest	**$7,855**	$213	$3,224
Cash paid for income taxes	**415**	10,581	158

See notes to audited consolidated financial statements.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations: TXCO Resources Inc. ("TXCO" or "Company"), formerly The Exploration Company of Delaware, Inc., 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 leases located in Texas. The Company also has interests in leases in Oklahoma, Louisiana, South Dakota, North Dakota and Montana.

Consolidation: The financial statements include the accounts of the Company and its wholly-owned subsidiaries. The subsidiaries engage in exploration, exploitation, development, production of oil and gas prospects, including oil sands, drill oil and gas wells for the consolidated group, own and operate a gas gathering system and the operation of 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 2006 and 2005, none of which were significant, have been reclassified to conform to the 2007 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, 2007, 2006 and 2005. 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 share ("EPS") is computed by dividing net income, adjusted for preferred stock dividends, by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation is similar to basic EPS, except the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. Common equivalent shares are excluded from the computation in periods in which they have an anti-dilutive effect. The Company uses the treasury stock method to calculate the impact of outstanding stock options and warrants. Any stock option or warrant for which the exercise price exceeds the average market price over the period would have an anti-dilutive effect on earnings per common share and, accordingly, would be excluded from the calculation. In order to determine the potential dilution from convertible preferred stock, the Company utilizes the "if-converted" method. If the written call option were "in-the-money," the Company would use the "reverse treasury stock method" to determine the dilutive impact.

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, 2007, the Company had deposits in excess of federal insurance protection totaling approximately $12.4 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.

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.

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.

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**
Net income as reported	$13,741
Deduct: Total stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects	(342)
Pro forma earnings	$13,399
Earnings per common share:	
Basic, as reported	$0.48
Basic, pro forma	0.47
Diluted, as reported	0.48
Diluted, pro forma	0.46

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 vested in 2006 was $129,600. Basic and diluted earnings per share for 2006 were each $0.004 lower than if the Company had continued to account for share-based compensation under APB 25. The Company did not have stock compensation expense related to stock options in 2007.

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 $154,100 in 2007, $75,200 in 2006 and $77,700 in 2005.

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:

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 was effective for the Company on January 1, 2007, and did not have a significant impact on its financial statements.

FASB Statement of Accounting Standard No. 157, "Fair Value Measurement" ("SFAS No. 157"): SFAS No. 157, issued in September 2006, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The standard applies whenever other standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. In February 2008, the FASB granted a one-year deferral of the effective date of this statement as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and goodwill impairment). SFAS No. 157 is effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. TXCO has completed its initial evaluation of the impact of SFAS No. 157 as it relates to its financial assets and liabilities and determined that its adoption is not expected to have a material impact on its financial position or results of operations.

FASB Statement of Accounting Standard No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"): SFAS No. 159, issued in February 2007, allows entities the option to measure eligible financial instruments at fair value as of specified dates. Such election, which may be applied on an instrument by instrument basis, is typically irrevocable once elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, and early application is allowed under certain circumstances. The Company does not expect the adoption of SFAS No. 159 to have a significant impact on the Company's consolidated financial statements.

In December 2007, Financial Accounting Standards Board (“FASB”) issued SFAS No. 141(R), "Business Combinations" ("SFAS 141(R)"), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS 141(R) will have an impact on accounting for business combinations once adopted, but the effect is dependent upon acquisitions at that time.

In December 2007, FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements -- an amendment of Accounting Research Bulletin No. 51" ("SFAS 160"), which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, changes in a parent's ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 is effective for fiscal years beginning after December 15, 2008. The Company does not currently have non-controlling interests in any of its subsidiaries.

NOTE B - PROPERTY AND EQUIPMENT

Property and equipment consists of the following at December 31:

(in thousands)	**2007**	**2006**
Oil and gas properties	$416,590	$164,014
Other property and equipment	11,731	8,650
Total Property and Equipment	428,321	172,664
Accumulated depreciation, depletion and amortization	(110,405)	(50,520)
Reserve for impairment on unproved properties	(2,975)	(2,570)
Net Property and Equipment	$314,941	$119,574

2007 Acquisition: On April 2, 2007, the Company closed on the purchase of Output Exploration LLC, a privately held, Houston-based exploration and production firm, for $95.6 million. The consideration for the purchase was $91.6 million in cash, subject to certain adjustments, and $4.0 million of TXCO common stock. Compared to pre-acquisition levels, the transaction effectively doubled our proved reserves and increased current oil and gas production by nearly two thirds. See Note L.

NOTE C - LONG-TERM DEBT

Debt consists of the following at December 31:

($'s in thousands)	**2007**	**2006**
Long-term:		
Note payable to a financial institution under bank credit facility (see below), with interest at LIBOR or the base rate plus applicable margin, quarterly payments of interest only, with maturity in 2012 and collateralized by all of the Company's proven oil and gas properties.	$100,000	$ -
Note payable to a financial institution under former 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
Short-term:		
Installment notes to finance company on insurance policies, with interest from 6.50% to 7.95%, monthly installments of $60, and unsecured.	399	-
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	$100,399	$2,618

The following is a schedule of principal maturities of debt as of December 31, 2007:

Year Ended December 31,	**Amount** *(in thousands)*
2008	$399
2009	-
2010	-
2011	-
2012	100,000
	$100,399

NOTE C - LONG-TERM DEBT - continued

Bank Credit Facilities: In connection with the acquisition described in Note B, the Company replaced its credit facility with Guaranty Bank with the following two facilities. Both of these facilities were amended in July 2007, as described below.

Senior Credit Agreement -- At December 31, 2007, the Company had a $125 million senior revolving credit facility with the Bank of Montreal, as agent, (the "SCA"). The SCA was entered into in April 2007 and expires in April 2011. The SCA was amended on July 25, 2007, decreasing the borrowing base from $60.0 million to $50.0 million and adding a requirement to hedge a portion of TXCO's projected oil and gas production.

At December 31, 2007, the borrowing base was $47 million, and there were no outstanding borrowings, leaving the unused borrowing base at $47 million. The SCA is secured by a first-priority security interest in TXCO's and certain of its subsidiaries' proved oil and natural gas reserves and in the equity interests of such subsidiaries. In addition, TXCO's obligations under the SCA are guaranteed by such subsidiaries. As of March 13, 2008, the balance outstanding under the SCA was $9.7 million with a weighted average interest rate of 5.01%, while the borrowing base was $50 million with $40.3 million unused.

Loans under the SCA are subject to floating rates of interest based on (1) the total amount outstanding under the SCA in relation to the borrowing base and (2) whether the loan is a LIBOR loan or a base rate loan. LIBOR loans bear interest at the LIBOR rate plus the applicable margin, and base rate loans bear interest at the base rate plus the applicable margin. The applicable margin varies with the ratio of total outstanding to the borrowing base. For base rate loans it ranges from zero to 100 basis points and for LIBOR rate loans it ranges from 150 to 250 basis points.

Under the amended SCA, the Company is required to pay a commitment fee on the difference between amounts available under the borrowing base and amounts actually borrowed. The commitment fee is (1) 0.375%, so long as the ratio of amounts outstanding under the SCA to the borrowing base is less than 30%, and (2) 0.50%, in the event such ratio is 30% or greater. Borrowings under the SCA may be repaid and reborrowed from time to time without penalty.

Term Loan Agreement -- At December 31, 2007, the Company had a $100 million five-year term loan facility, all of which was outstanding, with Bank of Montreal, as agent, (the "TLA") and certain other financial institutions party thereto with an interest rate of 9.875%. The TLA was amended on July 25, 2007, increasing the principal amount from $80 million to $100 million and extending the prepayment penalty date to July 25, 2008. As of March 13, 2008, the current interest rate is 7.625%.

Loans under the TLA are subject to floating rates of interest equal to, at the Company's option, the LIBOR rate plus 4.50% or the base rate plus 3.50%. The "LIBOR rate" and the base rate are calculated in the same manner as under the SCA.

Borrowings under the TLA may be repaid (but not reborrowed) subject to a prepayment premium equal to (i) 1.0%, if prepaid prior to July 25, 2008 and (ii) 0.0%, thereafter. Additionally, no prepayments are permitted if the ratio of the total amount outstanding under the SCA to the borrowing base thereunder exceeds 75% or if any default exists under the SCA.

Both the SCA and the TLA contain certain restrictive covenants which, among other things, limit the incurrence of additional debt, investments, liens, dividends, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, derivative contracts, sale leasebacks and other matters customarily restricted in such agreements. The amended SCA requires TXCO and its subsidiaries to not exceed a maximum consolidated leverage ratio of 3.00 to 1.00, while the amended TLA requires TXCO and its subsidiaries to not exceed a maximum consolidated leverage ratio of 3.50 to 1.00. Both the SCA and the TLA require TXCO and its subsidiaries to meet a minimum current assets to current liabilities ratio of 1.00 to 1.00 (after considering the unused portion of the SCA), a minimum interest coverage ratio of 2.00 to 1.00 and a minimum net present value to consolidated total debt ratio of 1.50 to 1.00. The ratios are calculated on a quarterly basis. Both agreements also contain customary events of default. If an event of default occurs and is continuing, lenders with a majority of the aggregate outstanding term loans may require Bank of Montreal, as agent, to declare all amounts outstanding under the SCA and TLA to be immediately due and payable.

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, 2005	$1,565
Liabilities incurred	131
Liabilities settled	-
Accretion expense	7
Balance, December 31, 2006	1,703
Revision to estimated plugging costs on existing liabilities (1)	1,362
Liabilities acquired (2)	896
Liabilities incurred	272
Liabilities settled	-
Accretion expense	-
Balance, December 31, 2007	$4,233

(1) Upward revision due to escalating costs in the field in excess of normal inflation.
(2) Asset retirement obligation of Output Exploration LLC when we acquired it.

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 $1,531,000 in 2007, $939,000 in 2006 and $989,000 in 2005. Future minimum rentals, for the next five years, under all non-cancelable leases and contracts are as follows:

Year Ended December 31,	**Amount** *(in thousands)*
2008	$776
2009	775
2010	731
2011	664
2012	584

Registration Rights: In November 2007, the Company entered into a Registration Rights Agreement (the "RRA") with the buyers listed therein whereby the Company agreed to file a registration statement, within 15 days of the last day on which an additional closing may be held, covering the resale of the shares of common stock to be acquired by the buyers upon conversion of their Series C preferred stock, described in Note F. The Company agreed to use its best efforts to cause such registration statement to be declared effective as soon as practicable, but in no event later than 105 days (if not subject to full SEC review), or 135 days (if subject to full SEC review), after the additional closing expiration date set forth in the Securities Purchase Agreement. Should the registration statement not be declared effective within that time period, or should the registration statement's effectiveness not be maintained in accordance with the terms of the RRA, the Company has agreed to pay affected buyers cash payments totaling 1% of the aggregate purchase price of those buyers' registrable securities included in such registration statement on each of certain specified dates, up to a maximum amount of 10% of the preferred stock's stated value. The aggregate stated value of the Series C preferred stock is currently $55.0 million therefore the maximum amount of payment would be $5.5 million. Since TXCO's management does not consider the likelihood of this outcome to be probable, no contingent liability was accrued.

NOTE E - COMMITMENTS AND CONTINGENCIES - continued

Pending or Threatened Litigation:

The Company is involved in various claims and legal actions arising in the ordinary course of business. The Company believes it is unlikely that the final outcome of any of the claims or proceedings to which it is a party would have a material adverse effect on the Company's financial position or results of operations.

NOTE F - STOCKHOLDERS' EQUITY

Preferred Stock: The Company has authorized 10 million shares of preferred stock. At December 31, 2007, 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.

In November 2007, the Company issued 55,000 shares of convertible perpetual preferred stock, Series C (the "Preferred"), all of which is outstanding at December 31, 2007. The Preferred has a stated value of $1,000 per share and a par value of $0.01 per share. It was issued in a private placement, raising a total of approximately $52.8 million after offering costs. The Preferred is convertible into the Company's common stock at a price of $14.48 per share, approximately 3.8 million shares. Holders of the Preferred are entitled to receive dividends, payable quarterly in cash or, at the Company's option, the Company's common stock, at the rate of 6.5% per annum, and have preference over the common stock in the event of liquidation. The Preferred requires TXCO and its subsidiaries to not exceed a maximum consolidated leverage ratio of 3.65 to 1.00 (as defined in the amended SCA). See Note N for discussion of Series E preferred stock in 2008.

Call Options - 2007: Concurrently with the issuance of the Preferred Series C, the Company entered into convertible preferred stock hedge transactions or "call spread" transactions intended to reduce potential dilution upon conversion of the Preferred. The purchased call option has an exercise price of $14.48 and covers approximately 3.8 million shares of the Company's common stock, which under most circumstances, represents the maximum number of shares of common stock underlying the Preferred. The sold call option covers approximately 3.8 million shares of the Company's common stock, has an exercise price of $18.10, and is expected to result in some dilution should the price of the Company's common stock exceed this exercise price.

These call options fall outside the scope of FAS 150, "Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios" and qualify for equity treatment under the guidance of EITF 00-19, "Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock." The net cost for these transactions, approximately $3.7 million, was recorded as a reduction to paid-in capital. See Note N for discussion of additional call spread transactions in 2008.

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

Stockholder Rights Agreement: On June 29, 2000, the Company adopted a Rights Agreement (the "Rights Agreement") whereby a dividend of one preferred share purchase right (a "Right") was paid for each outstanding share of TXCO common stock. The Rights Agreement 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 Agreement, 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 Agreement 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, 2007.

Dividend Restriction: The Bank Credit Facilities prohibit the declaration, or payment, of dividends to common stockholders.

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, 2007, 3,415,062 shares were authorized for grant and 805,562 shares remained available for grant. All currently outstanding options have 10-year terms that vest and become fully exercisable based on the specific terms imposed at the date of grant. No options have been granted since 2004.

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.

NOTE F - STOCKHOLDERS' EQUITY - continued

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

	Year Ended December 31,					
	2007		2006		2005	
(Shares in thousands)	**Shares Under Options**	**Weighted Average Exercise Price**	**Shares Under Options**	**Weighted Average Exercise Price**	**Shares Under Options**	**Weighted Average Exercise Price**
Outstanding, beginning of year	956	$2.90	1,254	$2.86	1,816	$2.99
Granted	-	N/A	-	N/A	-	N/A
Exercised	(243)	2.80	(293)	2.69	(529)	3.15
Forfeited / Expired	-	-	(5)	5.00	(33)	5.56
Outstanding, end of year	713	$2.94	956	$2.90	1,254	$2.86
Aggregate intrinsic value, end of year	$8,596		$9,975		$4,511	
Exercisable, end of year	613	$3.07	856	$2.99	864	$2.90
Aggregate intrinsic value, end of year	$7,390		$8,854		$3,079	
Weighted average fair value of options granted during the year	N/A		N/A		N/A	

The following table summarizes information about the options outstanding at December 31, 2007:

	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**
$2.125	450*	0.49 years	$2.125	350*	$2.125
2.96	66	3.59 years	2.96	66	2.96
4.38	64	5.47 years	4.38	64	4.38
5.00	133	6.75 years	5.00	133	5.00
	713*	2.39 years	$2.94	613*	$3.07

* In January 2008, options to purchase 300,000 shares of common stock at $2.125 per share were exercised. 100,000 shares that were not exercisable at year-end became exercisable during February 2008, when the market price for the Company's common stock reached $15.00 per share, and were exercised during March 2008.

Proceeds to the Company from the exercise of stock options related to stock-based compensation totaled $92,000 in 2007 and $227,000 in 2006, net of cashless exercises.

Stock Warrants*:* The following is a summary of warrants outstanding at December 31, 2007:

Purpose of Warrants	**Number of Shares** ***(in thousands)***	**Range of Prices**	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Life**
Financing	727	$4.25	$4.25	0.4 year

Proceeds to the Company from the exercise of warrants to purchase common stock totaled $570,000 during 2006. All 2007 exercises of warrants were done on a cashless basis.

NOTE F - STOCKHOLDERS' EQUITY - continued

Restricted Stock: During 2006 and 2007, the Company granted restricted stock as compensation to employees and non-employee directors under the 2005 Stock Incentive Plan. During 2007, shares with an aggregate fair value of $564,000 and a vesting term of one year were granted to non-employee directors, while shares with an aggregate fair value of $3.4 million and a three-year vesting period were granted to employees ($1.1 million aggregate fair value per year). During 2006 shares with an aggregate fair value of $0.4 million and a vesting term of one year were granted to non-employee directors along with shares with an aggregate fair value of $0.7 million and a vesting term of three years ($0.2 million aggregate fair value per year), while shares with an aggregate fair value of $2.1 million and a three-year vesting period were granted to employees ($0.7 million aggregate fair value per year). Compensation expense is recognized over the vesting periods.

	(in thousands)
Outstanding at December 31, 2005	-
Granted	349
Forfeited	(18)
Vested	(1)
Outstanding at December 31, 2006	330
Granted	349
Forfeited	(22)
Vested	(130)
Outstanding at December 31, 2007	527

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, 2007 and 2006:

(in thousands)	**2007**	**2006**	**2005**
Net income	$1,340	$7,241	$13,741
Other comprehensive income (loss):			
Deferred hedge gain (loss)	(6,873)	1,036	(2,881)
Income tax benefit (expense) of cash flow hedges	2,281	(372)	1,055
Total comprehensive income (loss)	$(3,252)	$7,905	$11,915

NOTE H - EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator of the earnings per share ("EPS") computation for both basic and diluted EPS:

	Year Ended December 31,		
	2007	**2006**	**2005**
Net Income	$1,340	$7,241	$13,741
Less: Preferred dividends	397	-	-
Income - basic earnings per share calculation	943	7,241	13,741
Add: Income impact of assumed conversions, if any	-	-	-
Income - diluted earnings per share calculation	$943	$7,241	$13,741
Weighted-average number of common shares:			
Basic	33,422	31,916	28,444
Effect of dilutive securities:			
Stock options and warrants	872	1,017	441
Restricted shares	446	314	-
Convertible preferred stock	-	-	-
Diluted	34,740	33,247	28,885
Earnings per common share:			
Basic	$0.03	$0.23	$0.48
Diluted	$0.03	$0.22	$0.48

For the year ended December 31, 2007, the calculation of weighted-average number of common shares for diluted EPS does not include 3,798,343 of potential common shares derived from convertible preferred stock, Series C, and 3,798,342 potential common shares derived from written call options, respectively, both issued in November 2007, because their effect would have been anti-dilutive. Any future dilution from conversion of the Preferred is expected to be offset by the Company's exercise of its purchased call options with the same exercise price. None of our outstanding stock options or warrants were anti-dilutive based on exercise price during the three-year period presented.

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)	**2007**	**2006**	**2005**
Current federal tax (benefit) expense	$(5,301)	$1,232	$4,851
Deferred federal tax expense (benefit)	4,458	1,429	(928)
Income tax expense (benefit)	$(843)	$2,661	$3,923
Deferred tax assets:			
Tax net operating loss carryforwards	$ 23,159	$ -	
Impairment of oil and gas properties	5,532	8,258	
Restricted stock compensation	362	399	
Other items	4,474	683	
Gross deferred tax assets	33,527	9,340	
Deferred tax liabilities:			
Intangible drilling costs and depreciation	(44,100)	(4,030)	
Other items	(1,434)	-	
Gross deferred tax liabilities	(45,534)	(4,030)	
Net deferred tax (liability) / asset	$(12,007)	$5,310	

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

(in thousands)	**2007**	**2006**	**2005**
Expected federal tax expense	$169	$3,664	$6,535
Change in valuation allowance	-	-	(1,642)
Statutory tax depletion and similar items	(1,012)	(1,003)	(970)
Income tax expense (benefit)	$(843)	$2,661	$3,923

The Company's tax net operating loss carryforward of approximately $60.4 million expires in 2027.

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	G
Year ended December 31, 2007	40%	15%	11%	5%	3%	-%	-%
Year ended December 31, 2006	5%	7%	15%	12%	8%	2%	-%
Year ended December 31, 2005	9%	-%	5%	11%	11%	14%	17%

NOTE K - COMMODITY HEDGING CONTRACTS AND ACTIVITY

Due to the volatility of oil and natural gas prices and requirements under TXCO's bank credit facility, the Company periodically enters into price-risk management transactions (e.g., swaps, collars and floors) for a portion of its oil and natural gas production. This allows it to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. These arrangements apply to only a portion of the Company's production, 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. In prior years, the Company 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 were 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) in the Stockholders' Equity section of the Consolidated Balance Sheets. The gain or loss in Other Comprehensive Income is reported on the Consolidated Statement of Operations as the hedged transactions occur. The hedges are highly effective, and therefore, no hedge ineffectiveness has been recorded.

The Company had cash flow hedges in place during January through April of 2007, which have now expired. New derivative agreements were entered into during the third and fourth quarters of 2007, in accordance with the terms of our term loan and revolving credit facilities.

The following table reflects the realized gains and losses from derivatives included in revenue on the Consolidated Statement of Operations:

(in thousands)	2007	2006	2005
Natural gas derivative realized settlements	$(1,372)	$(806)	$ -
Crude oil derivative realized settlements	(1,596)	(105)	-
Gain (loss) on derivatives	$(2,968)	$(911)	$ -

NOTE K - COMMODITY HEDGING CONTRACTS AND ACTIVITY - continued

The fair value of outstanding derivative contracts reflected on the balance sheet was as follows:

Trans-action Date	Trans-action Type	Beginning	Ending	Average Floor or Fixed Price Per Unit	Average Ceiling Price Per Unit	Volumes Per Month	Fair Value of Outstanding Derivative Contracts *(1)* as of December 31, 2007	December 31, 2006
							(in thousands)	
Natural Gas - mcf (2):								
08-12/07	Collar	01/01/2008	12/31/2008	$6.50	$10.22	97,000	$33	$ -
08-12/07	Collar	01/01/2009	12/31/2009	$6.50	$11.58	80,000	(57)	-
08-12/07	Collar	01/01/2010	06/30/2010	$6.50	$11.65	70,000	(43)	-
12/07	Collar	07/01/2010	12/31/2010	$6.50	$11.13	67,000	(63)	-
Crude Oil - Bbl (3):								
06/05	Fixed	11/01/2006	04/30/2007	$56.70	n/a	15,000	-	(321)
08-12/07	Collar	01/01/2008	12/31/2008	$67.31	$81.05	26,000	(4,758)	-
08-12/07	Collar	01/01/2009	12/31/2009	$66.18	$76.05	17,000	(2,845)	-
08-12/07	Collar	01/01/2010	06/30/2010	$66.43	$76.74	14,000	(990)	-
12/07	Collar	07/01/2010	12/31/2010	$75.00	$99.00	12,500	5	-
							$(8,718)	$(321)

(1) The fair value of the Company's outstanding transactions is presented on the balance sheet by counterparty. Amounts in parentheses indicate liabilities. All were designated as cash flow hedges.
(2) These natural gas hedges were entered into on a thousand cubic foot (mcf) delivered price basis, using the Houston Ship Channel Index, with settlement for each calendar month occurring following the expiration date, as determined by the contracts.
(3) 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.

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

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

NOTE L - ACQUISITIONS AND SALES OF OIL AND GAS PROPERTIES

Output Acquisition: On April 2, 2007, TXCO's acquisition of Output Exploration, LLC, a Delaware limited liability company ("Output"), was closed and became effective. Accordingly, the results of operations of Output are consolidated in the financial statements since that date.

In connection with the Merger, TXCO paid to the holders of Output equity interests an aggregate of approximately $95.6 million, consisting of $91.6 million in cash and approximately 339,000 shares of TXCO common stock (the "Reserve Shares"). The Reserve Shares are being held by an escrow agent to be released to TXCO to the extent necessary to satisfy indemnity claims made by TXCO under the Merger Agreement during the one-year period following the Merger. Any Reserve Shares not released to TXCO will be liquidated by the escrow agent and the net proceeds paid to the holders of Output equity interests converted in the Merger.

BMO Capital Markets served as financial advisor to TXCO. The Merger was funded through borrowings under the new Senior Credit Agreement and Term Loan Agreement described in Item 1.01 of the Current Report on Form 8-K, that was filed with the SEC on April 5, 2007, and summarized in Note C above.

Management believes that one of the most attractive aspects of Output is the similarity of its Fort Trinidad Field prospects to those in TXCO's core Maverick Basin operating area, allowing TXCO's technical and operations team to apply its knowledge of these formations to East Texas. The acquisition essentially doubles the Company's reserves and creates growth opportunities and greater exposure to the natural gas market.

The following table summarizes the final purchase price allocation to the acquired assets and liabilities based on their relative fair values:

Allocation of Purchase Price *(in thousands)*	
Proved properties	$91,096
Unproved properties	24,164
Pipeline equipment	13
Other assets	6,632
Liabilities assumed	(26,305)
	$95,600

The following unaudited pro forma data includes the results of operations as if the Output acquisition had been consummated on January 1, 2006. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

	For the Year Ended December 31,	
Pro Forma Income Statement Data *(in thousands)*	**2007**	**2006**
Revenues	**$99,867**	$101,916
(Loss)/ income from continuing operations, after pro forma provision for income taxes	**$(422)**	$5,193
(Loss)/ income from continuing operations available to common stockholders	**$(819)**	$5,193
(Loss)/ income from continuing operations available to common stockholders, per share:		
Basic	**$(0.02)**	$0.16
Diluted	**$(0.02)**	$0.15

NOTE L - ACQUISITIONS AND SALES OF OIL AND GAS PROPERTIES - continued

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)	**2007**	**2006**
Proved properties	$360,577	$147,681
Less accumulated depreciation, depletion and amortization	(108,175)	(70,574)
Net proved properties	252,402	77,107
Unproved properties:		
Drilling in-progress	34,782	30,623
Oil and gas leasehold acreage	21,231	6,997
Total unproved properties	56,013	37,620
Less reserve for impairment	(2,975)	(2,570)
Net unproved properties	53,038	35,050
Net capitalized cost	$305,440	$112,157

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

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

(in thousands, except per equivalent mcf data)	**2007**	**2006**	**2005**
Property acquisition costs, unproved	$51,966	$18,670	$9,684
Property development and exploration costs:			
Conventional oil and gas properties	224,858	51,293	31,903
Coalbed methane properties	-	3	76
Gathering system	17	113	388
Depreciation, depletion and amortization	35,922	23,627	12,377
Depletion per equivalent mcf of production	4.51	4.04	2.69

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.

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)	**2007**	**2006**	**2005**
Proved developed and undeveloped reserves:			
Natural gas (mmcf):			
Beginning of year	7,955	9,656	17,701
Extensions and discoveries	7,394	198	5
Reserves purchased	24,496	-	-
Sales volumes	(2,125)	(1,104)	(2,222)
Revisions of previous engineering estimates	5,561	(795)	(2,844)
Reserves sold	(981)	-	(2,984)
End of year	42,300	7,955	9,656
Crude Oil (mBbl):			
Beginning of year	5,580	4,957	3,374
Extensions and discoveries	719	778	522
Reserves purchased	2,543	-	-
Sales volumes	(974)	(791)	(397)
Revisions of previous engineering estimates	467	636	1,187
Reserves sold	(93)	-	271
End of year	8,242	5,580	4,957

Note: This table continues on the following page.

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

(in thousands)	**2007**	**2006**	**2005**
Proved developed reserves:			
Natural gas (mmcf):			
Beginning of year	6,286	7,846	13,087
End of year	28,946	6,286	7,846
Crude Oil (mBbl):			
Beginning of year	2,262	1,813	1,688
End of year	4,131	2,262	1,813

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 $6.445, $5.40 and $7.775 per mcf of gas and $92.75, $57.75 and $57.75 per barrel of oil as of December 31, 2007, 2006 and 2005. 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)	**2007**	**2006**	**2005**
Future cash inflows	$1,126,799	$371,475	$379,431
Future production and development costs	(410,254)	(182,459)	(167,659)
Future income tax expense	(156,835)	(37,901)	(53,419)
Future net cash flows	559,710	151,115	158,353
10% annual discount to reflect timing of net cash flows	(249,740)	(49,096)	(60,330)
Standardized measure of discounted future net cash flows relating to proved reserves	$309,970	$102,019	$98,023

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)	**2007**	**2006**	**2005**
Standardized measure, beginning of year	$102,019	$98,023	$65,462
Extensions and discoveries	53,946	32,880	19,410
Reserves purchased	118,100	-	-
Sales and transfers, net of production costs	(62,993)	(46,721)	(29,882)
Reserves sold	(5,545)	-	-
Revisions in quantity and price estimates	157,299	(1,280)	49,085
Net change in income taxes	(63,058)	9,315	(12,598)
Accretion of discount	10,202	9,802	6,546
Standardized measure, end of year	$309,970	$102,019	$98,023

NOTE N - SUBSEQUENT EVENTS

Preferred Stock Issuance: On February 28, 2008, TXCO entered into an agreement related to the sale in a private placement, of an aggregate of $20 million of shares of the Company's Series E Convertible Preferred Stock (the "Series E Preferred Stock") and the exchange of the issued and outstanding shares of its Series C Convertible Preferred Stock (the "Series C Preferred Stock") for shares of its Series D Convertible Preferred Stock (the "Series D Preferred Stock") pursuant to the Securities Purchase Agreement among the Company and the buyers listed therein. Closing and funding occurred on March 4, 2008.

The Series E Preferred has a stated value of $1,000 per share and a par value of $0.01 per share, and is convertible into approximately 1.15 million shares of the Company's common stock. Holders of the Series E Preferred are entitled to receive dividends, payable quarterly in cash or, at the Company's option, the Company's common stock, at the rate of 6.0% per annum and have preference over the common stock. The Series E Preferred requires TXCO and its subsidiaries to not exceed a maximum consolidated leverage ratio of 3.65 to 1.00 (as defined in the amended SCA).

Under the Securities Purchase Agreement, the buyers paid $1,000 for each share of Series E Preferred Stock and exchanged each share of Series C Preferred Stock for a share of Series D Preferred Stock. Buyers may convert their shares of Series D Preferred Stock and Series E Preferred Stock into shares of the Company’s common stock in accordance with the Certificate of Designations, Preferences and Rights of Series D Convertible Preferred Stock of TXCO Resources Inc. and the Certificate of Designations, Preferences and Rights of Series E Convertible Preferred Stock of TXCO Resources Inc., respectively, each of which is filed herewith and discussed below. Subject to certain terms and conditions, the buyers may purchase up to an additional $30 million of shares of Series D Preferred Stock by delivering written notice to the Company prior to March 20, 2008 (or, at the Company’s option, May 20, 2008).

The Securities Purchase Agreement includes representations, warranties, and covenants customary for a transaction of this type. In addition, the Company has granted the buyers a right of first refusal with respect to 50% of certain subsequent issuances of the Company’s equity securities that occur within a certain period of time after closing. Under the terms of the Securities Purchase Agreement, the Company has agreed to indemnify the buyers against certain liabilities.

The Company intends to use the net proceeds from the sale of the Series E Preferred Stock to complement funding of the Company’s 2008 CAPEX drilling program. In addition, the Company may use the proceeds in the short term to repay certain outstanding indebtedness, and to pay expenses of the offering and the costs of the call spread transactions discussed below, as well as other general corporate and working capital purposes.

Call Spread Transactions: In connection with the offer and sale of the Series E Preferred Stock, the Company has entered into convertible preferred stock hedge transactions, or "call spread" transactions, with one of the buyers of the Series E Preferred Stock (the "Counterparty"). These transactions are intended to reduce the potential dilution upon conversion of the Series E Preferred Stock, if the market value per share of the Company’s common stock at the time of exercise is greater than approximately 120% of the issue price (which corresponds to the initial conversion price of the Series E Preferred Stock). These transactions include a purchased call option and a sold call option. The Company’s net cost for these transactions totals approximately $1.3 million, which the Company will pay using a portion of the net proceeds of the Series E Preferred Stock offering. The purchased call option covers approximately the same number of shares of the Company’s common stock, par value $0.01 per share, which, under most circumstances, represents the maximum number of shares of common stock underlying the Series E Preferred Stock. The sold call option has an exercise price of 150% of the issue price and is expected to result in some dilution should the price of the Company’s common stock exceed this exercise price. The call spread transactions are separate agreements with the Counterparty; they are not governed by the Securities Purchase Agreement. Copies of the Call Option Transaction documents were filed as Exhibits 10.2 and 10.3 to the Company's Current Report on Form 8-K filed with the United States Securities and Exchange Commission on February 28, 2008.

NOTE O - Selected Quarterly Financial Information (Unaudited)

(In thousands, except earnings per share data)	**First**	**Second**	**Third**	**Fourth**	**Total**
2007					
Total revenues	$11,220	$22,336	$28,273	$32,077	$93,906
Income (loss) from operations	(2,596)	914	6,367	5,722	10,407
Net (loss) income	(1,892)	(1,314)	2,379	2,167	1,340
Income (loss)available to common stockholders	(1,892)	(1,314)	2,379	1,770	943
Earnings Per Share: ***(1)***					
Basic	$ (0.06)	$ (0.04)	$0.07	$0.05	$0.03
Diluted	(0.06)	(0.04)	0.07	0.05	0.03
2006					
Total revenues	$16,023	$19,552	$21,583	$15,260	$72,418
Income (loss) from operations	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: ***(1)***					
Basic	0.04	0.12	0.20	(0.13)	$0.23
Diluted	0.04	0.12	0.19	(0.13)	0.22

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

TXCO Resources Inc.
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, 2007				
Allowance for doubtful accounts, trade accounts	$27	$ -	$ -	$27
Impairment of oil and gas properties	2,570	405	-	2,975
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)	-