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

FORM 10-Q

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

For the quarterly period ended **September 30, 2006**
OR

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

For the transition period from _____________ to _________________

Commission File No. **0-9120**

TXCO
THE EXPLORATION COMPANY

THE EXPLORATION COMPANY OF DELAWARE, INC.
(Exact Name of Registrant as Specified in its Charter)

DELAWARE	**84-0793089**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer I.D. No.)

777 E. SONTERRA BLVD., SUITE 350 SAN ANTONIO, TEXAS 78258
(Address of principal executive offices)

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

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 whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of November 3, 2006.

Common Stock $0.01 par value	**33,107,648**
(Class of Stock)	(Number of Shares)

For more information go to www.txco.com.
The information at www.txco.com is not incorporated into this report.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

THE EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

($ in thousands)	**September 30, 2006**	December 31, 2005
Assets		
Current Assets		
Cash and equivalents	**$6,029**	$6,083
Accounts receivable, net	**9,573**	9,344
Prepaid expenses and other	**2,886**	1,620
Total Current Assets	**18,488**	17,047
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	**117,428**	84,467
Other Assets		
Deferred tax asset	**8,836**	7,242
Other assets	**590**	780
Total Other Assets	**9,426**	8,022
Total Assets	**$145,342**	$109,536

See notes to consolidated financial statements

THE EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

($ in thousands)	**September 30, 2006**	December 31, 2005
Liabilities and Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	**$7,818**	$10,003
Undistributed revenue	**1,414**	2,479
Current income taxes payable	**2,090**	4,952
Other payables and accrued liabilities	**4,290**	4,297
Derivative settlements payable	**217**	151
Accrued derivative obligation - short-term	**932**	2,084
Long-term debt, current portion	**124**	262
Total Current Liabilities	**16,885**	24,228
Long-Term Liabilities		
Long-term debt, net of current portion	**1**	1
Accrued derivative obligation - long-term	**-**	461
Asset retirement obligation	**1,691**	1,565
Total Long-Term Liabilities	**1,692**	2,027
Stockholders' Equity		
Preferred stock, Series A & Series B; authorized 10,000,000 shares; issued and outstanding -0- shares	**-**	-
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued 33,207,448 and 29,479,697 shares, outstanding 33,107,648 and 29,379,897 shares	**332**	295
Additional paid-in capital	**121,583**	89,680
Retained earnings / (accumulated deficit)	**7,021**	(4,622)
Less treasury stock, at cost, 99,800 shares	**(246)**	(246)
Accumulated other comprehensive loss, net of tax	**(1,925)**	(1,826)
Total Stockholders' Equity	**126,765**	83,281
Total Liabilities and Stockholders' Equity	**$145,342**	$109,536

See notes to consolidated financial statements

THE EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

(in thousands, except earnings per share data)	**Three Months Ended September 30, 2006**	Three Months Ended September 30, 2005
Revenues		
Oil and gas sales	**$18,067**	$10,950
Gas gathering operations	**3,511**	6,176
Other operating income	**5**	10
Total Revenues	**21,583**	17,136
Costs and Expenses		
Lease operations	**1,816**	1,613
Production taxes	**879**	608
Exploration expenses	**320**	476
Impairment and abandonments	**-**	780
Gas gathering operations	**3,555**	6,255
Depreciation, depletion and amortization	**4,539**	4,370
General and administrative	**2,105**	1,603
Total Costs and Expenses	**13,214**	15,705
Income from Operations	**8,369**	1,431
Other Income (Expense)		
Derivative mark-to-market gain (loss)	**1,319**	(7,099)
Derivative settlements loss	**(949)**	(547)
Interest expense	**(73)**	(1,076)
Interest income	**258**	11
Loan fee amortization	**(52)**	(32)
Gain on sale of assets	**-**	24,541
Total Other Income (Expense)	**503**	15,798
Income before income taxes	**8,872**	17,229
Income tax expense	**2,484**	1,940
Net Income	**$6,388**	$15,289
Earnings Per Share		
Basic earnings per share	**$0.20**	$0.54
Diluted earnings per share	**$0.19**	$0.53

See notes to consolidated financial statements

THE EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

(in thousands, except earnings per share data)	**Nine Months Ended September 30, 2006**	Nine Months Ended September 30, 2005
Revenues		
Oil and gas sales	**$44,389**	$27,511
Gas gathering operations	**12,730**	19,683
Other operating income	**40**	30
Total Revenues	**57,159**	47,224
Costs and Expenses		
Lease operations	**5,328**	5,021
Production taxes	**2,170**	1,599
Exploration expenses	**960**	1,827
Impairment and abandonments	**1,094**	1,935
Gas gathering operations	**12,930**	19,077
Depreciation, depletion and amortization	**10,892**	10,479
General and administrative	**5,666**	4,126
Total Costs and Expenses	**39,040**	44,064
Income from Operations	**18,119**	3,160
Other Income (Expense)		
Derivative mark-to-market gain (loss)	**1,787**	(10,832)
Derivative settlements loss	**(2,540)**	(1,000)
Interest expense	**(209)**	(2,878)
Interest income	**471**	35
Loan fee amortization	**(174)**	(68)
(Loss) gain on sale of assets	**(11)**	24,541
Total Other Income (Expense)	**(676)**	9,798
Income before income taxes	**17,443**	12,958
Income tax expense	**5,799**	1,990
Net Income	**$11,644**	$10,968
Earnings Per Share		
Basic earnings per share	**$0.37**	$0.39
Diluted earnings per share	**$0.35**	$0.38

See notes to consolidated financial statements

THE EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

(in thousands)	**Nine Months Ended September 30, 2006**	Nine Months Ended September 30, 2005
Operating Activities		
Net income	**$11,644**	$10,968
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**11,066**	10,547
Impairment and abandonments	**1,094**	1,935
Loss (gain) on sale of assets	**11**	(24,541)
Non-cash stock compensation expense	**974**	-
Deferred tax benefit	**(1,519)**	(1,198)
Non-cash derivative mark-to-market (gain) loss	**(1,787)**	10,832
Non-cash interest expense and accretion of liability - redeemable preferred stock	**-**	684
Changes in operating assets and liabilities:		
Receivables	**(229)**	(4,708)
Prepaid expenses and other	**(1,251)**	(451)
Accounts payable and accrued expenses	**(3,191)**	5,253
Current income taxes payable	**(2,862)**	3,003
Net cash provided by operating activities	**13,950**	12,324
Investing Activities		
Development and purchases of oil and gas properties	**(38,395)**	(35,606)
Purchase of other equipment	**(5,762)**	(20)
Proceeds from sale of assets	**19**	78,000
Net cash (used) provided by investing activities	**(44,138)**	42,374
Financing Activities		
Proceeds from issuance of common stock, net of expenses	**30,272**	1,487
Proceeds from long-term debt obligations	**9,300**	15,001
Payments on long-term debt obligations	**(9,300)**	(32,000)
Proceeds from installment obligations	**178**	122
Payments on installment obligations	**(316)**	(1,697)
Redemption of preferred stock	**-**	(16,000)
Net cash provided (used) by financing activities	**30,134**	(33,087)
Change in Cash and Equivalents	**(54)**	21,611
Cash and equivalents at beginning of period	**6,083**	3,118
Cash and Equivalents at End of Period	**$6,029**	$24,729

See notes to consolidated financial statements

1. Basis of Presentation

The accompanying unaudited consolidated financial statements of The Exploration Company ("TXCO" or "the Company") have been prepared in accordance with U.S. generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by U.S. generally accepted accounting principles for complete financial statements. The accounting policies followed by the Company are set forth in Note A to the audited consolidated financial statements contained in the Company's Annual Report on Form 10-K for the year ended December 31, 2005.

In the opinion of management, all adjustments (consisting of normal recurring adjustments) considered necessary for a fair presentation have been included. Certain reclassifications have been made to the prior period to conform to current presentation. For further information, refer to the consolidated financial statements and footnotes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2005.

2. Stock-based Compensation

The Company has stock-based employee compensation plans that are described more fully in Note F, "Stockholders' Equity," to the audited consolidated financial statements contained in the Company's Annual Report on Form 10-K for the year ended December 31, 2005. Total stock-based compensation expense recognized in the first nine months of 2006 was $974,000, while the related tax benefit recognized was $360,000. No comparable expense was recognized in the prior year.

As of September 30, 2006, the Company had outstanding options to purchase 1,010,500 shares of common stock at prices ranging from $0.98 to $5.00 per share. The options expire at various dates through September 2014. Of these, 910,500 were exercisable at quarter end.

Additionally, at September 30, 2006, the Company had outstanding exercisable warrants to purchase 966,500 shares of common stock at $4.25 per share. The warrants, which expire in May 2008, were issued as part of the private placement of 4.3 million shares in May 2004.

Stock Options: In prior years, the Company issued stock options as compensation to employees and non-employee directors. Generally, these options had a ten-year life and vested over two years for employees and three years for directors. Upon exercise, newly issued shares are utilized to fulfill the obligation. No options were granted in 2005 or 2006. The Board utilized restricted stock grants in lieu of stock options in 2006.

Prior to January 1, 2006, the Company accounted for the plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options was normally reflected in net income, as all options granted under the plans had an exercise price equal to, or greater than, the market value of the underlying common stock on the date of grant.

2. Stock-based Compensation - continued

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation for the periods shown:

Periods Ended September 30, 2005:	**Three Months**	**Nine Months**
(in thousands, except per share data)		
Net income as reported	$15,289	$10,968
Deduct: Total stock-based compensation expense determined under the fair value based method for all awards, net of related tax effects	494	370
Pro forma income	$14,795	$10,598
Earnings per common share:		
Basic, as reported	$0.54	$0.39
Basic, pro forma	0.52	0.37
Diluted, as reported	0.53	0.38
Diluted, pro forma	0.51	0.37

The Company adopted Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS No. 123R"), on January 1, 2006, using the modified-prospective transition method. SFAS No. 123R requires the measurement of compensation expense for the unvested portion of previously granted awards and any new awards using the grant date fair value and recording of such expense in the financial statements over the vesting period. The Company used the Black-Scholes option pricing model to compute the fair value which required the Company to make assumptions, as follows:

- The risk-free interest rate was based on the five-year U.S. Treasury bond rate at the date of grant.
- The dividend yield on the Company's common stock was assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.
- The market price volatility is computed in accordance with SFAS No. 123R.
- The term of the grants represents the weighted-average period that the stock options are expected to be outstanding.

For any future stock options awarded:

- the market price volatility will be based on historical prices for a period equal to the grant term.
- the grant term will be computed using the simplified method described in Staff Accounting Bulletin No. 107.

Non-cash stock compensation expense of $129,600 is being expensed over the first nine months of 2006, which represents the remaining vesting period, for the unvested portion of options outstanding at December 31, 2005.

Stock Option Activity:	**Number Outstanding**	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Term**	**Aggregate Intrinsic Value**
1995 Flexible Incentive Plan:*	*(in thousands)*		*(in years)*	*(in thousands)*
Outstanding at December 31, 2005	1,254	$2.86	4.3	$4,511
Granted	-	-		
Exercised	238	2.79		
Forfeited or Expired	5	5.00		
Outstanding at September 30, 2006 **	1,011	$2.87	3.6	$7,682
Exercisable at September 30, 2006	911	$2.95	3.8	$6,847

* There have been no options awarded under the 2005 Stock Incentive Plan.

** 100,000 shares become exercisable upon attaining a stock price target of $15.00.

2. Stock-based Compensation - continued

The total intrinsic value of options exercised during the nine months ended September 30, 2006, was $2,081,900. The Company received $453,000 in cash in connection with these exercises. Options to purchase 85,000 shares at $5.00 per share vested on September 30, 2006.

***Restricted Stock*:** During the first quarter of 2006, the Company granted 349,000 shares of restricted stock as compensation to employees and non-employee directors under its 2005 Stock Incentive Plan. Of these, 42,000 shares with a fair value of $369,000 vest in one year, and 307,000 with a fair value of $2.7 million vest over a three-year period ($0.9 million per year). The fair value is recognized as stock compensation expense (included in general and administrative expense on the Consolidated Statements of Operations) over the vesting periods.

Restricted Stock Activity:	**Shares**	**Weighted Average Grant Date Fair Value**
2005 Stock Incentive Plan:	*(in thousands)*	
Unvested restricted stock at December 31, 2005	-	
Granted	349	$9.00
Vested	*	8.79
Forfeited	7	8.79
Unvested restricted stock at September 30, 2006	342	$9.00

* 500 shares vested upon the death of an employee.

Stock Used to Acquire Goods or Services: During the second quarter of 2006, the Company issued 61,335 shares of its common stock to buy out an overriding royalty interest in certain of its leases.

3. Common Stock and Basic Income Per Share

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

	2006			2005		
(In thousands, except per share data)	**Shares ***	**Income**	**Per Share Amount**	Shares *	Income	Per Share Amount
Three Months Ended September 30						
Basic EPS:						
Net income (loss)	**32,715**	**$6,388**	**$0.20**	28,367	$15,289	$0.54
Effect of dilutive options	**1,368**	**-**	**(0.01)**	608	-	(0.01)
Dilutive EPS	**34,083**	**$6,388**	**$0.19**	28,975	$15,289	$0.53
Nine Months Ended September 30						
Basic EPS:						
Net income (loss)	**31,613**	**$11,644**	**$0.37**	28,303	$10,968	$0.39
Effect of dilutive options	**1,411**	**-**	**(0.02)**	205	-	(0.01)
Dilutive EPS	**33,024**	**$11,644**	**$0.35**	28,508	$10,968	$0.38

* Weighted average shares outstanding

4. Income Taxes

The Company recognizes deferred tax assets on differences in its basis for book and tax purposes. The Company's effective tax rate was 28% and 33% for the three- and nine-month periods ended September 30, 2006, respectively. The comparable rates for the periods ended September 30, 2005, were 11.2% and 15.4%.

5. Commodity Hedging Contracts and Activity

Due to the volatility of oil and natural gas prices, the Company, from time to time, enters into price-risk management transactions (e.g., swaps, collars and floors) for a portion of its oil and natural gas production. In certain cases, 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 may partially limit the Company's potential gains from future increases in prices. None of these instruments are used for trading purposes. On a quarterly basis, the Company's management sets all of the Company's price-risk management policies, including volumes, types of instruments and counterparties.

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

The outstanding hedges at September 30, 2006, and December 31, 2005, impacting the balance sheet were as follows:

Transaction						Fair Value of Outstanding Derivative Contracts *(1)* as of	
Date	**Type**	**Beginning**	**Ending**	**Price Per Unit**	**Volumes Per Month**	**September 30, 2006**	**December 31, 2005**
Crude oil (2):						*(in thousands)*	
Derivatives treated as investments:							
03/05	Fixed Price	11/01/2005	10/31/2006	$49.40	15,000	**$(207)**	$(1,995)
Derivatives treated as cash flow hedges:							
06/05	Fixed Price	11/01/2006	04/30/2007	$56.70	13,000	**(725)**	(550)
	Total fair value of derivative contracts					**$(932)**	$(2,545)

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

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

6. 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 three- and nine-month periods ended September 30, 2006, and 2005:

	Three Month Period		Nine Month Period	
(in thousands)	**2006**	**2005**	**2006**	**2005**
Net income	**$6,388**	$15,289	**$11,644**	$10,968
Other comprehensive income (loss):				
Change in fair value of cash flow hedges	**758**	(2,689)	**(175)**	(3,106)
Change in income tax benefit of cash flow hedges	**(281)**	1,135	**76**	1,149
Total comprehensive income	**$6,865**	$13,735	**$11,545**	$9,011

7. Long-Term Debt

Bank Credit Facility: The Company has a $50 million senior secured revolving credit facility with Guaranty Bank ("Facility"). The Facility was entered into in 2004 and expires in June 2008.

The Facility is collateralized by all of the Company's proven oil and gas properties, with the borrowing base established on current levels of TXCO's oil and gas reserves, and features semi-annual redeterminations. At September 30, 2006, the borrowing base, inclusive of tranche A and tranche B, was $32.0 million. At September 30, 2006, only $1,000 was outstanding at an interest rate of 8.25%. Interest under the Facility is based on, at TXCO's option, (a) the London Interbank Offered Rate ("LIBOR") plus an applicable margin ranging from 2.00% to 2.50% or (b) prime plus an applicable margin ranging from 0.00% to 0.25% ("floating rate"). The Facility provides the lender a commitment fee equal to 0.5% per annum on the unused borrowing base. The interest rate at September 30, 2006, was 8.25% computed in accordance with (b) above.

The Facility contains additional terms and conditions consistent with similarly positioned companies. These conditions include various restrictive covenants such as minimum levels of interest coverage, tangible net worth and current ratio, a maximum debt to EBITDAX ratio, restricting the payment of dividends, and prohibiting a change of control or incurring additional debt. The ratios used for determining compliance with the Facility are defined within that Facility and may not be equivalent to other uses of those terms. The Company was in compliance with all such covenants at September 30, 2006.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Certain statements in this report that are not historical in nature, including statements of TXCO's and management's expectations, intentions, plans and beliefs, are inherently uncertain and are "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934. The following discussion should be read in conjunction with the unaudited consolidated financial statements and notes thereto included in this Form 10-Q, and with the Company's latest audited consolidated financial statements and notes thereto, and Management's Discussion and Analysis, as reported in its Form 10-K for the year ended December 31, 2005. See the "Disclosure Regarding Forward Looking Statements" section at the end of this Item 2.

Overview

Unless the context requires otherwise, when we refer to "TXCO", "the Company", "we", "us" or "our", we are describing The Exploration Company of Delaware, Inc. The following discussion of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the notes thereto included in this Form 10-Q.

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

We currently have three drilling rigs under contract and in operation on our extensive 644,000-acre position in the Maverick Basin and one completion rig operating in the Marfa Basin. Our emphasis thus far this year has been on the Glen Rose and San Miguel formations. We began 42 new wells and 12 re-entries in Texas through October 2006, including 29 in the Glen Rose Porosity. We participated in one new well in the Williston Basin. The drilling rig we purchased in March 2006 is currently undergoing refurbishment and is expected to be placed in service late this year. Our revised 2006 capital expenditures budget ("CAPEX") includes funds for the drilling or re-entry of more than 60 wells (more than 30 in the Glen Rose Porosity), as well as funds for completion of a number of wells in progress at year-end 2005 and for infrastructure improvements. A 26-well program focusing on the San Miguel tar sand formation, originally planned for late this year, will start in 2007 due to delays in the start of steam injection in the San Miguel tar sand pilot project.

Due to the number of promising prospects on our Maverick Basin acreage, as well as higher oil and gas prices, drilling activity has remained high during the last several years. (For further discussion of this activity, see "Principal Areas of Activity" and "Drilling Activity" in Item 1 of our Annual Report on Form 10-K for the year ended December 31, 2005). The resulting increased expenditures continue to translate into increased reserves as we establish adequate production history. Recognition of additional reserves on newly drilled wells requires a period of sustained production, causing a delay between the expenditures and the recognition of reserves.

Net income was $6.4 million or $0.19 per diluted share for the quarter ended September 30, 2006, and $11.6 million or $0.35 per diluted share for the nine months ended September 30, 2006. These compare with net income of $15.3 million or $0.53 per diluted share for the prior-year quarter, and $11.0 million or $0.38 per diluted share for the nine months ended September 30, 2005. Increased revenues and lower losses on derivatives for 2006 resulted in net income that exceeded the then-record net income recorded for the nine-month period ended September 30, 2005, which included a $24.5 million gain on the sale of assets. Operating income increased by $6.9 million and $15.0 million for the quarter and year-to-date periods, as compared to the same periods in the prior year, due to higher sales volumes, on a barrels of oil equivalent ("BOE") basis, and higher average realized oil prices. Net hedging losses decreased by $8.0 million and $11.1 million for the three- and nine-month periods of 2006, from the prior-year periods, favorably impacting net income. Sales volumes were up 49.1% and 25.5%, on a BOE basis, during the third-quarter and first-nine-month periods of 2006, as compared with the prior-year periods, despite the September 2005 sale of approximately 20% of then current total production. Lower interest expense also contributed to the improvement in net income. These factors are discussed in "Results of Operations."

SFAS No. 123(R) required the recording of non-cash compensation expense in 2006 for stock-based compensation that reduced earnings per diluted share by $0.01 for third-quarter 2006, and $0.03 for the year-to-date period of 2006. No comparable expense was recognized during the 2005 periods.

Net cash provided by operating activities for the first nine months of 2006 was $14.0 million, as compared to $12.3 million for same period in 2005. Net cash provided by operating activities, excluding changes in operating assets and liabilities, was $21.5 million for the first nine months of 2006, up from $9.2 million during the comparable 2005 period.

	Third Quarter			First Nine Months		
Operational Data	**2006**	**2005**	**Change**	**2006**	**2005**	**Change**
Oil sales volumes (mBbls)	242.2	110.4	+ 119.4%	587.7	266.0	+ 121.0%
Gas sales volumes (MMcf)	278.5	498.8	- 44.2%	864.1	1,902.3	- 54.6%
Combined sales volumes (mBOE)	288.6	193.6	+ 49.1%	731.7	583.0	+ 25.5%
Net residue and NGL sales volumes (MMbtu)	406,714	757,759	- 46.3%	1,453,419	2,320,318	- 37.4%
Oil average realized sales price Bbl	$66.51	$60.23	+ 10.4%	$64.68	$53.00	+ 22.0%
Gas average realized sales price per Mcf	$7.02	$8.62	- 18.5%	$7.38	$7.05	+ 4.6%
Residue & NGL average realized sales price per MMbtu	$8.10	$7.97	+ 1.7%	$8.32	$8.29	+ 0.4%
Oil - average daily sales (BOPD)	2,633	1,200	+ 119.4%	2,153	974	+ 121.0%
Gas - average daily sales (Mcfd)	3,027	5,422	- 44.2%	3,165	6,968	- 54.6%
Combined average daily sales (BOED)	3,137	2,104	+ 49.1%	2,680	2,136	+ 25.5%

Liquidity and Capital Resources

Liquidity is a measure of ability to access cash. Our primary needs for cash are for exploration, development and acquisitions of oil and gas properties, repayment of contractual obligations and working capital funding. We have historically addressed our long-term liquidity requirements through cash provided by operating activities, the issuance of debt and equity securities when market conditions permit, sale of non-strategic assets, and more recently through our credit facility. The prices for future oil and natural gas production and the level of production have significant impacts on operating cash flows and cannot be predicted with any degree of certainty. We continue to examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of common stock, the sales of strategic and 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.

Bank Credit Facility: We have a $50 million senior secured revolving credit facility with Guaranty Bank (the "Facility" or "credit facility"). The Facility was entered into in 2004 and expires in June 2008.

The Facility is collateralized by all of the Company's proven oil and gas properties, with the borrowing base established on current levels of TXCO's oil and gas reserves, and features semi-annual redeterminations. At September 30, 2006, the borrowing base, inclusive of tranche A and tranche B, was $32.0 million. At September 30, 2006, only $1,000 was outstanding at an interest rate of 8.25%. Interest under the Facility is based on, at TXCO's option, (a) the London Interbank Offered Rate ("LIBOR") plus an applicable margin ranging from 2.00% to 2.50% or (b) prime plus an applicable margin ranging from 0.00% to 0.25% ("floating rate"). The Facility provides the lender a commitment fee equal to 0.5% per annum on the unused borrowing base. The interest rate at September 30, 2006, was 8.25% computed in accordance with (b) above.

The Facility contains additional terms and conditions consistent with similarly positioned companies. These conditions include various restrictive covenants such as minimum levels of interest coverage, tangible net worth and current ratio, a maximum debt to EBITDAX ratio, restricting the payment of dividends other than the dividends payable under the redeemable preferred stock, and prohibiting a change of control or incurring additional debt. The Facility's original requirement for hedging a percentage of production, under certain circumstances, was removed during 2005. At September 30, 2006, we were in compliance with all covenants.

Private Placement of Common Stock: On March 30, 2006, our Board of Directors approved a private placement of our common stock to a group of institutional investors. On March 31, 2006, related stock subscriptions for three million shares of our common stock were received via the placement agents. On April 4, 2006, the transaction was closed and funded, providing approximately $29.8 million to supplement our capital resources. These new funds allow the expansion of our capital expenditure budget for 2006 in order to accelerate our development in the Glen Rose Porosity, as well as other new projects. See "Part II, Item 2 - Unregistered Sales of Equity Securities and Use of Proceeds" in our Form 10-Q filed with the SEC on May 10, 2006, for additional information.

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

Risk Management Activities -- Commodity Hedging Contracts: Due to the volatility of oil and natural gas prices and former requirements under our bank credit facility, we from time to time enter into price-risk management transactions (e.g., swaps, collars and floors) for a portion of our oil and natural gas production. In certain cases, this allows us to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. These arrangements apply to only a portion of our production, and provide only partial price protection against declines in oil and natural gas prices, and may partially limit our potential gains from future increases in prices. None of these instruments are used for trading purposes. On a quarterly basis, management sets all of our price-risk management policies, including volumes, types of instruments and counterparties. These policies are implemented by management through the execution of trades by the Chief Financial Officer after consultation with and concurrence by the President and the Board of Directors. Our Board of Directors monitors our price-risk management policies and trades.

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

Sources and Uses of Cash: At December 31, 2005, our cash reserves were $6.1 million. During the first nine months of 2006, cash provided by operating activities was $14.0 million. In addition, net proceeds from the private placement of common stock of $29.8 million, borrowings under the Facility of $9.3 million, and proceeds from the exercise of options and warrants totaling $0.9 million, resulted in total cash available of $60.1 million for use in meeting our ongoing operational and development needs.

Payments on installment debt during first-quarter 2006 totaled $0.1 million in principal, with interest payments of $27,000. Federal income taxes paid during the quarter totaled $3.0 million. We applied $9.8 million to fund the ongoing development of our oil and gas producing properties.

During second-quarter 2006, payments on debt totaled $9.4 million in principal, with interest payments of $97,000. We applied $8.9 million to fund the ongoing development of our oil and gas producing properties.

In third-quarter 2006, payments on debt totaled $0.1 million in principal, with interest payments of $40,000. Federal income taxes paid during the quarter totaled $6.6 million. We applied $19.7 million to fund the ongoing development of our oil and gas producing properties.

Adjusted for the impact of the derivative liabilities on current liabilities, we ended the third quarter of 2006 with positive working capital of $2.8 million compared to negative working capital of $4.9 million at December 31, 2005. At September 30, 2006, with the same adjustment, our current ratio was 1.17 to 1 compared to 0.78 to 1 at year-end 2005. Including the $1.1 million of derivative current liabilities at September 30, 2006, positive working capital was $1.6 million with a current ratio of 1.09 to 1. At year-end 2005, including the $2.2 million of derivative current liabilities, negative working capital was $7.2 million, while the current ratio was 0.70 to 1.

We completed the third quarter of 2006 with an unused borrowing base of $32 million under our Facility. Year-to-date 2006 cash provided by operating activities was $14.0 million, compared to $12.3 million in the comparable prior-year period. Before changes in operating assets and liabilities, year-to-date 2006 cash flow from operating activities was $21.5 million compared to $9.2 million for the same 2005 period, a 132.8% increase. Changes in operating assets and liabilities include increases or decreases in receivables, accounts payable and prepaid expenses from the prior year-end balances.

Results of Operations

The following table highlights the change for 2006 from the comparable periods in 2005:

Selected Income Statement Items:	Third Quarter $ thousands		Third Quarter %		First Nine Months $ thousands		First Nine Months %	
Oil and gas revenues	+	7,117	+	65.0	+	16,878	+	61.4
Lease operating expense	+	203	+	12.6	+	307	+	6.1
Depreciation, depletion & amortization	+	169	+	3.9	+	413	+	3.9
Income from operations	+	6,938	+	484.9	+	14,959	+	473.4
Derivative mark-to-market gain / loss	-	8,419		n/m	-	12,619		n/m
Derivative settlements loss	+	402	+	73.5	+	1,540	+	154.0
(Loss) gain on sale of assets	-	24,541	-	n/m	-	24,552	-	n/m
Net income	-	8,901	-	58.2	+	676	+	6.2

n/m - % change not meaningful due to move from loss to income, or gain to loss

The following table summarizes the change for 2006 from the comparable periods in 2005:

Change in Gas Gathering Results:	Third Quarter $ thousands		Third Quarter %		First Nine Months $ thousands		First Nine Months %	
Revenues:								
Third-party natural gas sales	-	2,067	-	42.8	-	4,926	-	32.1
Natural gas liquids sales	-	674	-	55.7	-	2,223	-	57.0
Transportation and other revenue	+	76	+	54.5	+	196	+	44.5
Total gas gathering revenues	-	2,665	-	43.1	-	6,953	-	35.3
Expense:								
Third-party gas purchases	-	2,653	-	44.6	-	5,977	-	32.9
Transportation and marketing expenses	-	78	-	78.5	-	182	-	72.4
Direct operating costs	+	31	+	15.6	+	13	+	2.0
Total gas gathering operations expense	-	2,700	-	43.2	-	6,146	-	32.2
Gross margin	-	35	-	44.8	-	807		n/m
Operational data								
Total sales volumes (MMBtu)	-	351	-	46.3	-	867	-	37.4
Average sales price (per MMBtu)	+	0.14	+	1.7	-	0.03	-	0.3

n/m - % change not meaningful due to move from income to loss

Three Months Ended September 30, 2006, Compared with Three Months Ended September 30, 2005:

Revenues

The increase in oil and gas revenue is attributable to higher oil sales volumes at higher realized prices, partially offset by a decline in gas sales. Oil sales volumes increased 119.4% primarily due to Glen Rose Porosity wells put on production since September 30, 2005. This increase was partially offset by 44.2% lower gas volumes, reflecting the sale of a portion of our gas production to EnCana Oil & Gas (USA) Inc. ("EnCana") in September 2005 and normal maturing gas well decline curves. In addition, due to our focus on drilling oil wells this year, we are not replacing gas-specific reserves at the present time. Sales volumes increased 49.1% on a BOE basis. Average realized sales prices for oil were up 10.4%, while those for natural gas were down 18.5%.

Lease Operations

The 12.6% increase in lease operating expenses primarily reflects costs related to new Maverick Basin oil and gas wells placed on production since September 30, 2005, and cost increases related to the high demand for services in field operations, partially offset by the elimination of costs related to wells sold to EnCana.

Gas Gathering

Our gas gathering system transports our natural gas production to various markets. It also transports production for other owners at a set rate per million British thermal units ("MMBtu"). It sells gas at several points along the system with a significant portion being delivered to purchasers through the Enterprise/Gulf Terra Pipeline System or to purchasers behind the Duke Three Rivers processing plant. The gas is processed and the natural gas liquids are removed. The residue gas is then sold to various purchasers. We receive a share of the liquids revenues. Natural gas pricing fluctuations are reflected at the wellhead for our operated gas properties.

Gas gathering operations revenues decreased 43.1% due to lower volumes for third-party natural gas sales and natural gas liquids sales. The impact was partially offset by higher realized prices on natural gas liquids sales. Lower third-party natural gas sales volumes are coming through the system due to declining production on area leases and a partner's election to market their gas rather than sell it through TXCO.

Impairment

Impairment decreased due to our focus on the highly successful Glen Rose Porosity field this year..

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased 3.9%, as costs related to new wells placed on production exceeded the reduction for the elimination of wells sold to EnCana last year.

General and Administrative ("G&A")

	Third Quarter		**Change from prior year period**		
	2006	**2005**			
Non-cash, stock compensation expense	$357.6	$ -	+	$357.6	n/m%
Other G&A expense	1,747.4	1,602.8	+	144.7	9.0%
Total G&A expense	$2,105.0	$1,602.8	+	$502.3	31.3%

n/m - not meaningful due to no comparable expense in the prior year

G&A expense represents approximately 9.8% of total revenues. The increase was primarily due to 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. Excluding the stock compensation expense, G&A would have represented 8.1% of total revenues.

Salary-related costs were up $0.2 million related to 13 additional full-time employees hired since September 30, 2005, with associated salaries, wages and benefits, along with merit increases across the organization. Eight of the new employees are employed by our wholly-owned subsidiary, TXCO Drilling Corp. ("TDC"), which will operate the rig purchased earlier this year. TDC is staffing up to begin operations late this year.

Derivative Gain / Loss

A non-cash, mark-to-market gain was accrued on hedges of future sales volumes. This is a $8.4 million change from the loss recorded in the prior-year period. This was due to the elimination of the natural gas hedges during October 2005, and the short period remaining on the oil hedges. Derivative settlement losses on the closed periods amounted to $0.9 million, up from $0.5 million, bringing the net pre-tax hedging gain to $0.4 million, as compared to a loss of $7.6 million in the prior-year quarter.

Interest Expense

Interest expense decreased by $1.0 million due to lower levels of borrowings under the Facility.

(Loss) gain on sale of assets

Third-quarter 2005 included a $24.5 million gain on the sale of certain assets to EnCana. No comparable gain was recognized during 2006.

Nine Months Ended September 30, 2006, Compared with Nine Months Ended September 30, 2005:

Revenues

The increase in oil and gas revenue is attributable to higher oil sales volumes at higher average realized prices, partially offset by a decline in gas production. Oil sales volumes increased 121.0% primarily due to Glen Rose Porosity wells put on production since September 30, 2005. This increase was offset by 54.6% lower gas production, reflecting the sale of a portion of our gas production to EnCana in September 2005 and normal maturing gas well decline curves. In addition, we are not replacing gas-specific reserves at the present time due to our focus on drilling oil wells this year. Sales volumes increased 25.5% on a BOE basis. Average realized sales prices for oil and natural gas were up 22.0% and 4.6%, respectively.

Lease Operations

The 6.1% increase in lease operating expenses reflects costs related to new Maverick Basin oil and gas wells placed on production since September 30, 2005, and cost increases related to the high demand for services in field operations, partially offset by the elimination of costs related to wells sold to EnCana.

Gas Gathering

Gas gathering operations revenues decreased 35.3% due to lower volumes for third-party natural gas sales and natural gas liquids sales. The impact was partially offset by higher realized prices on natural gas liquids. Lower third-party natural gas sales volumes are coming through the system due to declining production on area leases and a partner's election to market their gas rather than sell it through TXCO.

Impairment

Impairment decreased 43.5% due to our focus on the highly successful Glen Rose Porosity field this year**.**

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased 3.9%. The major component of this increase was higher depletion, up $0.8 million, offset by $0.4 million lower 3-D seismic amortization related to projects retired in conjunction with the sale of assets to EnCana.

General and Administrative ("G&A")

	First Nine Months		**Change from prior year period**		
	2006	**2005**			
Non-cash, stock compensation expense	$973.6	$ -	+	$973.6	n/m%
Other G&A expense	4,692.3	4,126.2	+	566.1	13.7%
Total G&A expense	$5,665.9	$4,126.2	+	$1,539.7	37.3%

n/m - not meaningful due to no comparable expense in the prior year

G&A represents approximately 9.9% of total revenues. The increase was primarily due to 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 under SFAS No. 123R. No comparable expenses were recorded during 2005. Excluding the stock compensation expense, 2006 G&A would have represented 8.2% of total revenues, down from 8.7% in the prior-year period.

Salary-related costs were up $0.4 million related to 13 additional full-time employees hired since September 30, 2005, with associated salaries, wages and benefits, along with merit increases throughout the organization. Eight of the new employees are employed by our wholly-owned subsidiary, TDC, which is staffing up to operate the rig purchased earlier this year.

Derivative Gain / Loss

We accrued a non-cash, mark-to-market gain of $1.8 million on hedges of future sales volumes compared with a $10.8 million non-cash, mark-to-market loss in the prior-year period. The change is primarily due to the elimination of the natural gas hedges during October 2005 and lower remaining hedged oil volumes. Derivative settlement losses on the closed periods amounted to $2.5 million, up from $1.0 million, bringing the net pre-tax hedging loss to $0.8 million, as compared to $11.8 million in the prior-year period.

Interest Expense

Interest expense decreased by $2.7 million due to lower levels of borrowings under the Facility.

(Loss) gain on sale of assets

Third quarter 2005 included a $24.5 million gain on the sale of certain assets to EnCana. No comparable gain was recognized during 2006.

Drilling Activities

We drilled or participated in drilling 54 wells in the first nine months of 2006. Of these wells, 52 were in the Maverick Basin and one each in the Marfa and Williston Basins. At September 30, 2006, 29 of these wells were on production, eight wells were completed and awaiting hook-up, 11 wells were to be completed or re-completed, and six wells remained drilling. Additionally, two wells that were in progress at year-end 2005 were placed on production in 2006. We focused primarily on the Glen Rose and San Miguel formations thus far in 2006. By comparison, we participated in 42 wells during the first nine months of 2005 targeting the Georgetown, San Miguel and Glen Rose intervals. The following table shows net daily sales for the periods presented:

	Third Quarter			First Nine Months		
Average net daily sales volumes :	**2006**	**2005**	**Change**	**2006**	**2005**	**Change**
Oil, BOPD	**2,633**	1,200	+119.4%	**2,153**	974	+121.0%
Natural gas, Mcfd	**3,027**	5,422	-44.2%	**3,165**	6,968	-54.6%
Oil equivalent, BOED	**3,137**	2,104	+49.1%	**2,680**	2,135	+25.5%

In October 2006, TXCO spud one well, targeting the Glen Rose Porosity formation, bringing total wells spud in 2006 to 55. At October 31, 2006, 37 of these wells were producing, seven were completed and awaiting hook-up, eight wells were to be completed or re-completed, and three wells remained drilling.

In September 2005, approximately 20% of then-current total production, primarily from gas properties, was sold to EnCana. Normal production declines were experienced on natural gas wells in the first nine months of 2006, as only one new gas well was put on production to offset declines on maturing wells.

There are three rigs under contract for our, or a partner's, account to facilitate drilling or re-entry of over 60 wells, during 2006. The drilling rig we purchased in March 2006 is currently undergoing refurbishment and is now expected to be placed in service late this year.

Glen Rose Porosity - During the first nine months of 2006, we drilled 28 Porosity wells, up from 14 in the same period of 2005. One Porosity well was begun during October 2006. Currently, of the 29 total 2006 wells, 18 are on production, one completed well awaits hook-up, three are in completion or re-completion, two continue drilling, one awaits transfer to an operating partner, and four are under evaluation as disposal wells. Due to a mechanical failure in the wellbore, the operator expects to plug the Comanche 2-44 after the hunting season moratorium. This well is included in the three wells in completion above. Glen Rose Porosity average daily sales for third-quarter 2006 were 2,341 BOPD, compared to 2,019 BOPD for the prior quarter and 834 BOPD for the comparable prior-year quarter. Glen Rose Porosity average daily sales for the first nine months of 2006 were 1,852 BOPD, compared with 485BOPD for the same period in 2005.

Glen Rose Porosity targets represent the largest portion of our 2006 CAPEX budget. We currently plan to drill or re-enter over 30 new wells in the Porosity during 2006. In October 2006, we began drilling on one new porosity well.

Glen Rose Shoal/Reefs - During the first nine months of 2006, we drilled one shoal and one reef well. Currently the shoal well is in completion/re-completion, while the reef well is producing natural gas. Two wells targeting a Glen Rose reef or shoal were started in the first nine months of 2005.

Glen Rose average daily sales for third-quarter 2006, excluding Porosity production, were 10 BOPD and 2.8 MMcfd, compared to 26 BOPD and 2.9 MMcfd for the prior quarter and 20 BOPD and 3.6 MMcfd for the prior-year quarter. Glen Rose average daily sales, excluding Porosity production, for the first nine months of 2006 were 17 BOPD and 2.9 MMcfe, compared with 21 BOPD and 4.0 MMcfd for the prior-year period. We currently plan to drill five shoal/reef wells during 2006.

Georgetown - We started four Georgetown wells during the first nine months of 2006, down from 14 projects in the prior-year period. Two of the 2006 wells are producing, while the other two are in completion/re-completion. Our 2006 CAPEX budget includes 10 wells. Georgetown average daily sales for third-quarter 2006 were 31 BOPD and 0.1 MMcfd, compared to 40 BOPD and 0.2 MMcfd for the prior quarter, and 113 BOPD and 1.7 MMcfd for the prior-year quarter. Georgetown average daily sales for the first nine months of 2006 were 43 BOPD and 0.1 MMcfd, compared with 163 BOPD and 2.61 MMcfd for the prior-year period.

The drop in Georgetown production from the prior-year period, and the reduced Georgetown activity, reflects the sale of our interest in this formation on certain properties to EnCana in September 2005. We continue to hold a 100% working interest in the Georgetown formation across most of the northern portion of our leaseblock.

Pena Creek San Miguel - San Miguel average daily sales for third-quarter 2006 were 171 BOPD, compared to 140 BOPD for the prior quarter, and 151.4 BOPD for the prior-year quarter. We started 15 San Miguel wells during the first nine months of 2006, compared with six during the same prior year period. Currently all of the 15 San Miguel wells started this year are producing. Our CAPEX budget called for 10 Pena Creek San Miguel wells in 2006.

San Miguel Tar Sand - We continue to participate in a two-well pilot test of the Tar Sand formation with our partner, Pearl Exploration and Production Ltd. Our CAPEX budget called for 26 Tar Sand wells in 2006. This program has been postponed until early 2007 due to delays encountered on the cyclic steam injection test.

Pearsall - Together with our partner, EnCana Oil & Gas (USA) Inc., we are moving forward with our Pearsall shale delineation project. Our first well targeting this formation was spud during third-quarter 2006 and continues operations. EnCana's extensive completion testing and evaluation process is expected to continue through year end. No Pearsall wells were drilled in 2005. Our CAPEX budget projected up to eight Pearsall wells to be drilled. The timing and number of these wells is under the control of EnCana as operator. If the first well proves successful, we expect additional drilling activity in 2007. For further discussion see "Part I, Item I - Business - Maverick Basin Plays" in our Annual Report on Form 10-K for the year ended December 31, 2005.

Marfa Basin - We participated in the re-entry of the Simpson 1 well bore during third-quarter 2006. Testing is underway on the well. Continental Resources Inc., our 50% partner in this acreage, serves as operator for the lease block. Additionally, one new well is currently planned for 2007.

Disclosure Regarding Forward Looking Statements

Statements in this Form 10-Q which are not historical, including statements regarding TXCO's or management's intentions, hopes, beliefs, expectations, representations, projections, estimations, plans or predictions of the future, are forwarding-looking statements and are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Such statements include those relating to expected drilling plans, including the timing, category, number, depth, cost and/or success of wells to be drilled, expected geological formations or the availability of specific services or technologies. It is important to note that actual results may differ materially from the results predicted in any such forward-looking statements. Investors are cautioned that all forward-looking statements involve risks and uncertainty. These risks and uncertainties include: the costs and accidental risks inherent in exploring and developing new oil and natural gas reserves, the price for which such reserves and production can be sold, environmental concerns affecting the drilling of oil and natural gas wells, impairment of oil and gas properties due to depletion or other causes, the uncertainties inherent in estimating quantities of proved reserves and cash flows, as well as general market conditions, competition and pricing. Please refer to the Risk Factors section of our Form 10-K for the year ended December 31, 2005, and the additional risk factors included in Part II, Item 1A of this Form 10-Q. This and all our previously filed documents are on file at the Securities and Exchange Commission and can be viewed on our Web site at www.txco.com. Copies of the filings are available from our Corporate Secretary without charge.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk represents the risk of loss that may impact the financial position, results of operations, or cash flows due to adverse changes in financial market prices, including interest rate risk, and other relevant market rate or price increases.

We are exposed to market risk through interest rates related to our credit facility borrowing. The credit facility borrowings are based on the LIBOR or prime rate plus an applicable margin and are used to assist in meeting our working capital needs. As of September 30, 2006, we had borrowings under our bank credit facility of $1,000. Assuming an increase in either the LIBOR or prime rate of interest of 100 basis points, interest expense would not increase materially.

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 during 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. In the normal course of business we enter into hedging transactions, including fixed price and ratio swaps to mitigate exposure to commodity price movements, but not for trading or speculative purposes.

During 2004 and 2005, due to the instability of prices and to achieve a more predictable cash flow, we put in place natural gas and crude oil swaps for a portion of our 2005 and 2006 production. Please refer to Note 5 to the consolidated financial statements included herein for additional information. While the use of these arrangements limits the benefit of increases in the price of oil and natural gas, it also limits the downside risk of adverse price movements.

The following is a list of derivative contracts outstanding as of September 30, 2006:

Transaction				Price	Volumes
Date	**Type**	**Beginning**	**Ending**	**Per Unit**	**Per Month**
Crude oil (1):					
Derivatives treated as investments:					
03/05	Fixed Price	11/01/2005	10/31/2006	$49.40	15,000
Derivatives treated as cash flow hedges:					
06/05	Fixed Price	11/01/2006	04/30/2007	$56.70	13,000

(1) 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.

At September 30, 2006, the fair value of the outstanding hedges was a liability of approximately $1.1 million. A 10% change in the commodity price per unit would cause the fair value of the hedges to increase or decrease by approximately $110,000.

For additional information, see also our Annual Report on Form 10-K for the year ended December 31, 2005, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

ITEM 4. CONTROLS AND PROCEDURES.

The SEC has adopted rules requiring reporting companies to maintain disclosure controls and procedures to provide reasonable assurance that a registrant is able to record, process, summarize and report the information required in the registrant's quarterly and annual reports under the Securities Exchange Act of 1934 (the "Exchange Act"). While we believe that our existing disclosure controls and procedures have been effective to accomplish these objectives, we intend to continue to examine, refine and formalize our disclosure controls and procedures and to monitor ongoing developments in this area.

Based on their evaluation as of September 30, 2006, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures (as defined in Rule 13a-15(e) or 15d-15(e) under the Exchange Act) are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is: (1) recorded, processed, summarized and reported within the time periods as specified in the SEC's rules and forms, and (2) accumulated and communicated to our management, including our chief executive and chief financial officers, to allow timely decisions regarding required disclosure.

There have not been any changes in our internal control over financial reporting (as such term is defined in Rule 13a-15(f) or 15d-15(f) under the Exchange Act) during the fiscal quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are involved in litigation arising out of our operations in the ordinary course of business. We maintain liability insurance, including product liability coverage, in amounts deemed adequate by management. To date, aggregate costs to us for claims, including product liability actions, have not been material. However, an uninsured or partially insured claim, or claim for which indemnification is not available, could have a material adverse effect on our financial condition or results of operations. We believe that there are no claims or litigation pending, the outcome of which could have a material adverse effect on our financial position or results of operations. However, due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim or proceeding will not have a material adverse effect on our results of operations for the fiscal period in which such resolution occurs.

ITEM 1A. RISK FACTORS

In addition to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005, please note the following risk factors.

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.

Instituted in 1999, our Rights Plan and certain provisions in our Restated Certificate of Incorporation may inhibit a takeover of the Company regardless of whether such takeover is in the best interest of our stockholders.

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

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

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

None

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

a) Exhibit 31.1 Certification of Chief Executive Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended filed herewith.

b) Exhibit 31.2 Certification of Chief Financial Officer required pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended filed herewith.

c) Exhibit 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 filed herewith.

e) Exhibit 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 filed herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE EXPLORATION COMPANY
(Registrant)

/s/ P. Mark Stark
P. Mark Stark,
Chief Financial Officer

Date: November 9, 2006