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, 2007**

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 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 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**

THE EXPLORATION COMPANY OF DELAWARE, INC.
(Former Name)

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 2, 2007.

Common Stock $0.01 par value	**34,162,619**
(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

TXCO RESOURCES INC.
Consolidated Balance Sheets
(Unaudited)

($ in thousands)	**September 30, 2007**	December 31, 2006
Assets		
Current Assets		
Cash and equivalents	**$ 6,798**	$ 3,882
Accounts receivable, net	**17,291**	9,132
Federal income tax receivable	**8,903**	4,468
Prepaid expenses and other	**5,143**	887
Accrued derivative asset - short-term	**105**	-
Total Current Assets	**38,240**	18,369
Property and Equipment, net - successful efforts method of accounting for oil and gas properties	**281,681**	119,574
Other Assets		
Deferred tax asset	**2,558**	5,310
Deferred financing fees	**2,377**	60
Accrued derivative asset - long-term	**55**	-
Other assets	**1,286**	488
Total Other Assets	**6,276**	5,858
Total Assets	**$ 326,197**	$ 143,801

See notes to consolidated financial statements

TXCO RESOURCES INC.
Consolidated Balance Sheets
(Unaudited)

($ in thousands)	**September 30, 2007**	December 31, 2006
Liabilities and Stockholders' Equity		
Current Liabilities		
Accounts payable, trade	**$ 16,829**	$ 7,969
Undistributed revenue	**1,698**	1,035
Notes payable	**190**	267
Derivative settlements payable	**111**	70
Accrued derivative obligation - short-term	**1,131**	321
Other payables and accrued liabilities	**12,259**	6,433
Total Current Liabilities	**32,218**	16,095
Long-Term Liabilities		
Long-term debt	**144,250**	2,351
Accrued derivative obligation - long-term	**1,404**	-
Deferred income taxes - long-term	**16,532**	-
Asset retirement obligation	**4,177**	1,703
Total Long-Term Liabilities	**166,363**	4,054
Stockholders' Equity		
Preferred stock, Series A & Series B; authorized 10,000,000 shares; issued and outstanding -0- shares	**-**	-
Common stock, par value $.01 per share; authorized 100,000,000 shares; issued 34,281,038 and 33,290,698 shares, outstanding 34,162,619 and 33,190,898 shares	**343**	333
Additional paid-in capital	**127,443**	122,108
Retained earnings	**1,791**	2,619
Accumulated other comprehensive loss, net of tax	**(1,496)**	(1,162)
Less treasury stock, at cost, 118,419 and 99,800 shares	**(465)**	(246)
Total Stockholders' Equity	**127,616**	123,652
Total Liabilities and Stockholders' Equity	**$ 326,197**	$ 143,801

See notes to consolidated financial statements

TXCO RESOURCES INC.
Consolidated Statements Of Operations
(Unaudited)

(in thousands, except earnings per share data)	**Three Months Ended September 30, 2007**	Three Months Ended September 30, 2006
Revenues		
Oil and gas sales	**$ 25,012**	$ 18,067
Gas gathering operations	**3,227**	3,511
Other operating income	**34**	5
Total Revenues	**28,273**	21,583
Costs and Expenses		
Lease operations	**3,137**	1,816
Production taxes	**1,418**	879
Exploration expenses, including dry hole costs	**269**	320
Impairment and abandonments	**(1,092)**	-
Gas gathering operations	**3,432**	3,555
Depreciation, depletion and amortization	**11,632**	4,539
General and administrative	**3,110**	2,105
Total Costs and Expenses	**21,906**	13,214
Income from Operations	**6,367**	8,369
Other Income (Expense)		
Derivative mark-to-market gain	**-**	1,319
Derivative settlements loss	**-**	(949)
Interest expense	**(3,227)**	(73)
Interest income	**135**	258
Loan fee amortization	**(175)**	(52)
Total Other Income (Expense)	**(3,267)**	503
Income before income taxes	**3,100**	8,872
Income tax (benefit) expense -- current	**(50)**	3,603
deferred	**771**	(1,119)
Net Income	**$ 2,379**	$ 6,388
Earnings Per Share		
Basic earnings per share	**$ 0.07**	$ 0.20
Diluted earnings per share	**$ 0.07**	$ 0.19

See notes to consolidated financial statements

TXCO RESOURCES INC.
Consolidated Statements Of Operations
(Unaudited)

(in thousands, except earnings per share data)	**Nine Months Ended September 30, 2007**	Nine Months Ended September 30, 2006
Revenues		
Oil and gas sales	**$ 52,873**	$ 44,389
Gas gathering operations	**8,872**	12,730
Other operating income	**84**	40
Total Revenues	**61,829**	57,159
Costs and Expenses		
Lease operations	**10,035**	5,328
Production taxes	**3,014**	2,170
Exploration expenses, including dry hole costs	**923**	960
Impairment and abandonments	**289**	1,094
Gas gathering operations	**9,670**	12,930
Depreciation, depletion and amortization	**25,217**	10,892
General and administrative	**7,996**	5,666
Total Costs and Expenses	**57,144**	39,040
Income from Operations	**4,685**	18,119
Other Income (Expense)		
Derivative mark-to-market gain	**-**	1,787
Derivative settlements loss	**-**	(2,540)
Interest expense	**(6,367)**	(209)
Interest income	**238**	471
Loan fee amortization	**(344)**	(174)
Loss on sale of assets	**-**	(11)
Total Other Income (Expense)	**(6,473)**	(676)
(Loss) income before income taxes	**(1,788)**	17,443
Income tax (benefit) expense -- current	**(5,301)**	7,318
deferred	**4,340**	(1,519)
Net (Loss) Income	**$ (827)**	$ 11,644
(Loss) Earnings Per Share		
Basic (loss) earnings per share	**$ (0.02)**	$ 0.37
Diluted (loss) earnings per share	**$ (0.02)**	$ 0.35

See notes to consolidated financial statements

TXCO RESOURCES INC.
Consolidated Statements Of Cash Flows
(Unaudited)

(in thousands, except earnings per share data)	**Nine Months Ended September 30, 2007**	Nine Months Ended September 30, 2006
Operating Activities		
Net (loss) income	**$ (827)**	$ 11,644
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**25,562**	11,066
Impairment, abandonments and dry hole costs	**743**	1,094
Deferred tax expense (benefit)	**4,340**	(1,519)
Loss on sale of asset	**-**	11
Non-cash stock compensation expense	**1,184**	974
Non-cash derivative mark-to-market loss	**-**	(1,787)
Non-cash change in derivative obligations	**1,524**	-
Changes in operating assets and liabilities:		
Receivables	**(8,160)**	(229)
Prepaid expenses and other	**(7,714)**	(1,251)
Accounts payable and accrued expenses	**15,431**	(3,191)
Current income taxes (receivable) payable	**(4,747)**	(2,862)
Net cash provided by operating activities	**27,336**	13,950
Investing Activities		
Development and purchases of oil and gas properties	**(68,141)**	(38,395)
Purchase of other equipment	**(2,317)**	(5,762)
Business acquisition	**(95,994)**	-
Proceeds from sale of assets	**-**	19
Net cash used by investing activities	**(166,452)**	(44,138)
Financing Activities		
Proceeds from bank credit facility	**164,750**	9,300
Payments on bank credit facility	**(22,851)**	(9,300)
Proceeds from installment and other obligations	**341**	178
Payments on installment and other obligations	**(418)**	(316)
Proceeds from issuance of common stock, net of expenses	**429**	30,272
Purchase of treasury shares	**(219)**	-
Net cash provided by financing activities	**142,032**	30,134
Change in Cash and Equivalents	**2,916**	(54)
Cash and equivalents at beginning of period	**3,882**	6,083
Cash and Equivalents at End of Period	**$ 6,798**	$ 6,029

See notes to consolidated financial statements

TXCO RESOURCES INC.
Notes To Consolidated Financial Statements
Periods Ended September 30, 2007, and September 30, 2006 (Unaudited)

1. Basis of Presentation

The accompanying unaudited consolidated financial statements of TXCO Resources Inc. ("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, 2006.

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, 2006.

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, 2006. Total stock-based compensation expense recognized was $1,184,000 and $974,000, in the first nine months of 2007 and 2006, respectively.

Stock Options: In prior years, the Company issued stock options as compensation to employees and non-employee directors under its 1995 Flexible Incentive Plan. 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 have been granted since 2004.

As of September 30, 2007, the Company had outstanding options to purchase 718,750 shares of common stock at prices ranging from $2.125 to $5.00 per share. The options expire at various dates through September 2014. Of these, 618,750 were exercisable at quarter end.

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, 2006	956	$2.90	3.3	$9,974
Exercised	237			
Outstanding at September 30, 2007 **	719	2.94	2.65	$4,326
Exercisable at September 30, 2007	619	3.07	2.98	$3,642

* 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

***Restricted Stock*:** During 2006 and 2007, the Company granted restricted stock as compensation to employees and non-employee directors under its 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). 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.

2. Stock-based Compensation - continued

Restricted Stock Activity:	**Shares**	**Weighted Average Grant Date Fair Value**
2005 Stock Incentive Plan:	*(in thousands)*	
Unvested restricted stock at December 31, 2006	330	$9.01
Granted	349	11.28
Vested	130	8.97
Forfeited	4	9.99
Unvested restricted stock at September 30, 2007	545	$10.46

Warrants: At September 30, 2007, the Company had outstanding exercisable warrants to purchase 726,500 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 Used to Acquire Goods or Services: During April 2007, the Company issued 338,983 shares of its common stock, with an aggregate fair value of $4.0 million, in a private placement as partial payment for its acquisition of Output Exploration LLC, a privately held, Houston-based exploration and production firm. See Note 8 "Output Acquisition" for additional information regarding this transaction.

3. Earnings Per Share

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

	2007			2006		
(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	**33,578**	**$ 2,379**	**$ 0.07**	32,715	$ 6,388	$ 0.20
Effect of dilutive options	**1,328**	**-**	**-**	1,368	-	(0.01)
Dilutive EPS	**34,906**	**$ 2,379**	**$ 0.07**	34,083	$ 6,388	$ 0.19
Nine Months Ended September 30						
Basic EPS:						
Net (loss) income	**33,355**	**$ (827)**	**$ (0.02)**	31,613	$ 11,644	$ 0.37
Effect of dilutive options	**n/a****	**-**	**-**	1,411	-	(0.02)
Dilutive EPS	**33,355**	**$ (827)**	**$ (0.02)**	33,024	$ 11,644	$ 0.35

* Weighted average shares outstanding ** Not applicable due to net loss for the period

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 23.3% and 53.8% for the three- and nine-month periods ended September 30, 2007, respectively. The Company's effective tax rates have changed due primarily to changes in the Texas Margin (franchise) tax laws.

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109." FIN 48 prescribes a comprehensive model for how companies should recognize, measure, present and disclose in their financial statements uncertain tax positions taken or expected to be taken on a tax return. Under FIN 48, tax positions are recognized in our consolidated financial statements as the largest amount of tax benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with tax authorities assuming full knowledge of the position and all relevant facts. These amounts are subsequently reevaluated and changes are recognized as adjustments to current period tax expense. FIN 48 also revised disclosure requirements to include an annual tabular rollforward of unrecognized tax benefits.

4. Income Taxes - continued

The Company adopted the provisions of FIN 48 on January 1, 2007. The adoption did not result in a material adjustment to its tax liability for unrecognized income tax benefits.

If applicable, we would recognize interest and penalties related to uncertain tax positions in interest expense. As of September 30, 2007, we had not accrued interest related to uncertain tax positions because we have no tax positions that we believe are uncertain. The tax years 2002-2006 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject. Before the Company acquired Output Exploration and OPEX Energy LLC ("OPEX") in April 2007, the Internal Revenue Service began a review of OPEX's federal tax returns for 2003 through 2005. The examination has not yet concluded. OPEX is now a wholly-owned subsidiary of the Company.

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. When used, 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 could 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 reflected 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 quarter 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 statement of operations:

	Nine Months Ended September 30,	
	2007	**2006**
	(in thousands)	
Natural gas derivative realized settlements	$(1,397)	$ -
Crude oil derivative realized settlements	(268)	-
Gain (loss) on derivatives	$(1,665)	$ -

5. Commodity Hedging Contracts and Activity - continued

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

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Volumes Per Month	Fair Value of Outstanding Derivative Contracts *(1)* as of September 30, 2007	Fair Value of Outstanding Derivative Contracts *(1)* as of December 31, 2006
						(in thousands)	
Natural Gas (2):							
08/07	Collar	09/01/2007	12/31/2007	$6.50-$6.85	75,000 mcf	$-	$ -
08/07	Collar	09/01/2007	12/31/2007	$6.50-$6.80	25,000 mcf	67	-
08/07	Collar	01/01/2008	12/31/2008	$6.50-$10.40	65,000 mcf	39	-
08/07	Collar	01/01/2008	12/31/2008	$6.50-$10.35	20,000 mcf	19	-
08/07	Collar	01/01/2009	12/31/2009	$6.50-$11.65	55,000 mcf	-	-
08/07	Collar	01/01/2009	12/31/2009	$6.50-$11.60	15,000 mcf	19	-
08/07	Collar	01/01/2010	06/30/2010	$6.50-$11.65	45,000 mcf	10	-
08/07	Collar	01/01/2010	06/30/2010	$6.50-$11.60	15,000 mcf	6	-
Crude Oil (3):							
06/05	Swap	11/01/2006	04/30/2007	$56.70	13,000 Bbl	-	(321)
08/07	Collar	09/01/2007	12/31/2007	$65-$76.10	21,000 Bbl	(404)	-
08/07	Collar	09/01/2007	12/31/2007	$65-$75.50	9,000 Bbl	(192)	-
08/07	Collar	01/01/2008	12/31/2008	$65-$74.00	6,000 Bbl	(347)	-
08/07	Collar	01/01/2008	12/31/2008	$65-$73.80	14,000 Bbl	(828)	-
08/07	Collar	01/01/2009	12/31/2009	$65-$73.00	4,000 Bbl	(157)	-
08/07	Collar	01/01/2009	12/31/2009	$65-$72.80	11,000 Bbl	(439)	-
08/07	Collar	01/01/2010	06/30/2010	$65-$73.00	4,000 Bbl	(54)	-
08/07	Collar	01/01/2010	06/30/2010	$65-$72.80	8,000 Bbl	(114)	-
						$(2,375)	$(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.

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, 2007, and 2006:

	Three Month Period		Nine Month Period	
(in thousands)	**2007**	**2006**	**2007**	**2006**
Net income (loss)	$ **2,379**	$ 6,388	$ **(827)**	$ 11,644
Other comprehensive income (loss):				
Deferred hedge gain (loss)	**(2,375)**	758	**(530)**	(175)
Income tax (expense) benefit of cash flow hedges	**879**	(281)	**196**	76
Total comprehensive (loss) income	$ **883**	$ 6,865	$ **(1,161)**	$ 11,545

7. Long-Term Debt

Bank Credit Facilities: In connection with the acquisition described in Note 8, 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 September 30, 2007, the Company had a $125 million senior revolving credit facility with the Bank of Montreal (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 that the Company's term loan facility was increased from $80 million to $100 million.

At September 30, 2007, the borrowing base was $50.0 million, $44.3 million was outstanding at a weighted average interest rate of 7.585% and the unused borrowing base was $5.7 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 October 31, 2007, the balance outstanding under the SCA was $46.3 million with a weighted average interest rate of 7.65%.

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, TXCO 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 September 30, 2007, the Company had a $100 million five-year term loan facility with Bank of Montreal (the "TLA") and certain other financial institutions party thereto with a current interest rate of 9.875%. The TLA was amended on July 25, 2007, increasing the principal amount from $80 million and extending the prepayment penalty date to July 25, 2008.

Loans under the TLA are subject to floating rates of interest equal to, at TXCO’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.

7. Long-Term Debt - continued

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 and TLA require TXCO and its subsidiaries to meet a maximum consolidated leverage ratio of 3.00 to 1.00, a minimum current assets to current liabilities ratio of 1.00 to 1.00, 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 to declare all amounts outstanding under the SCA and TLA to be immediately due and payable.

8. 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 these financial statements since that date. Pursuant to the terms of the Agreement and Plan of Merger, dated as of February 20, 2007, as amended (the "Merger Agreement"), by and among TXCO, Output Acquisition Corp., a Texas corporation and wholly-owned subsidiary of TXCO ("Merger Sub"), and Output, Output merged with and into Merger Sub (the "Merger"), with Merger Sub continuing as the surviving corporation and a wholly-owned subsidiary of TXCO.

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 7 above. Concurrent with the closing, TXCO elected to terminate all hedges assumed in the acquisition with a payment of $4.8 million.

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)*

Oil and gas properties:	Proved	$ 114,235
	Unproved	726
	Pipeline equipment	189
	Other assets	5,873
Total		$ 121,023

8. Output Acquisition - continued

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.

	Three Month Period		Nine Month Period	
Pro Forma Income Statement Data *(in thousands)*	**2007**	**2006**	**2007**	**2006**
Revenues	$ **28,273**	$ 29,158	$ **67,790**	$ 80,834
Income (loss) from continuing operations, after pro forma provision for income taxes	$ **2,379**	$ 6,132	$ **(2,589)**	$ 10,651
Income (loss) from continuing operations, per share:				
Basic	$ **0.07**	$ 0.19	$ **(0.08)**	$ 0.34
Diluted	$ **0.07**	$ 0.18	$ **(0.08)**	$ 0.32

9. Recent Accounting Pronouncements

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. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. Early adoption is permitted. The Company is currently evaluating the requirements of SFAS No. 157 and has not yet determined what impact, if any, adoption of SFAS No. 157 would have on the Company's consolidated financial statements.

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. The Company is currently evaluating the requirements of SFAS No. 159 and has not yet determined what impact, if any, application of SFAS No. 159 would have on the Company's consolidated financial statements.

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, 2006. 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 TXCO Resources 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, the onshore Gulf Coast region, the Marfa Basin of Texas and the Midcontinent region of western Oklahoma. We have a consistent record of long-term growth in proved oil and gas reserves, leasehold acreage position, production and cash flow through our established exploration, exploitation and development programs. Our business strategy is to build 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 six drilling rigs under contract and in operation on our Maverick Basin acreage, one rig in the Ft. Trinidad Field in East Texas, and two additional rigs in Oklahoma. Our emphasis thus far this year has been on the Glen Rose and San Miguel formations. We began 48 new wells and 18 re-entries in the Maverick Basin through October 31, including 33 in the Glen Rose Porosity. Through October 31, 2007, we participated in one new well and two re-entries in the Williston Basin, one re-entry in the Marfa Basin, one new well in Fayette County, and 10 wells on acreage obtained in the Output Exploration acquisition, discussed below. Our revised 2007 capital expenditures budget ("CAPEX") calls for $85 million to $90 million to be invested in drilling operations. This includes funds for the drilling or re-entry of about 90 wells in the Maverick Basin (more than 35 in the Glen Rose Porosity), and about 30 wells in other areas, as well as funds for completion of a number of wells in progress at year-end 2006 and for infrastructure improvements. We believe the unused borrowing base on our revolving credit 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 2007.

Due to the number of promising prospects throughout our focus areas, as well as high 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 Part I, Item 1 of our Annual Report on Form 10-K for the year ended December 31, 2006). 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.

On April 2, 2007, we closed on the acquisition of Output Exploration LLC ("Output"). Our year-to-date 2007 results include six months of Output's activity. This acquisition impacted many of our income statement and balance sheet accounts significantly, rendering comparisons to the prior year periods less meaningful. The acquisition nearly doubled our proved reserves and significantly increased our natural gas sales volumes. The consideration for the purchase was $91.6 million in cash, subject to certain adjustments, and 339,000 shares of our common stock. In addition, we assumed certain debts of Output. Concurrent with the closing, we elected to terminate all hedges assumed in the acquisition with a payment of $4.8 million. BMO Capital Markets served as financial advisor to TXCO. See the "Bank Credit Facilities" section below for discussion of the related financing.

Oil and gas sales revenues increased 38.4% for third-quarter 2007, and 19.1% for year-to-date 2007, compared to the same periods of 2006. Sales volumes were up 37.3% and 27.4% on a thousand cubic feet equivalent ("mcfe"), for the same periods. Average realized prices for third-quarter 2007 were up $5.08 per barrel of oil ("bo") and down $0.25 per thousand cubic feet of natural gas ("mcf") compared to third-quarter 2006, excluding the impact of hedges. Average realized prices for year-to-date 2007 were down $0.34 per bo and $0.25 per mcf, excluding the impact of hedges, compared with the same period last year. Total costs and expenses increased 65.8% for third-quarter 2007 and 46.4% for year-to-date 2007 compared with the prior year periods. Lease operating expenses increased by 72.7% for the quarter and 88.3% for the year-to-date period from the prior year periods. Depreciation, depletion and amortization increased by 156.3% for the third quarter and 131.5% for year-to-date 2007 compared with the prior year periods. These factors resulted in the net income of $2.4 million and net loss of $0.8 million, for the three- and nine-month periods ended September 30, 2007, respectively. In the prior year periods, we recorded net income of $6.4 million and $11.6 million, respectively.

Net cash provided by operating activities for year-to-date 2007 was $27.3 million, up from $14.0 million for the same period in 2006. Net cash provided by operating activities excluding changes in operating assets and liabilities was $32.5 million for year-to-date 2007, up from $21.5 million during the comparable 2006 period.

Operational Data	**Three Months**				**Nine Months**			
for the periods ending September 30	**2007**	**2006**	**% Change**		**2007**	**2006**	**% Change**	
Oil sales volumes (mbbls)	287.5	242.2	+	18.7	679.6	587.7	+	15.6
Gas sales volumes (mmcf)	652.0	278.5	+	134.1	1,517.3	864.1	+	75.6
Combined sales volumes (mboe)	396.2	288.6	+	37.3	932.5	731.7	+	27.4
Combined sales volumes (mmcfe)	2,377.0	1,731.8	+	37.3	5,594.8	4,390.5	+	27.4
Net residue and NGL sales volumes (mmbtu)	370,892	406,714	-	8.8	979,171	1,453,419	-	32.6
Oil average realized sales price bbl, excluding hedging impact	$71.59	$66.51	+	7.6	$64.34	$64.68	-	0.5
Gas average realized sales price per mcf, excluding hedging impact	$6.77	$7.02	-	3.6	$7.13	$7.38	-	3.4
Residue & NGL average realized sales price per mmbtu	$7.97	$8.10	-	1.6	$8.37	$8.32	+	0.6
Oil - average daily sales (bopd)	3,125	2,633	+	18.7	2,489	2,153	+	15.6
Gas - average daily sales (mcfd)	7,087	3,027	+	134.1	5,558	3,165	+	75.6
Combined average daily sales (mboed)	4,306	3,137	+	37.3	3,416	2,680	+	27.4
Combined average daily sales (mmcfed)	25,837	18,824	+	37.3	20,494	16,082	+	27.4

Liquidity and Capital Resources

Liquidity is a measure of ability to access cash. Our primary needs for cash are for exploration, exploitation, development and acquisition 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 facilities. 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 equity securities, 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 Facilities: In connection with our acquisition of Output, we replaced our credit facility with Guaranty Bank with the following two facilities in April 2007. Both of these facilities were amended in July 2007, as described below.

Senior Credit Agreement -- At September 30, 2007, we had a $125 million senior revolving credit facility with the Bank of Montreal (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 that our term loan facility was increased from $80 million to $100 million.

At September 30, 2007, the borrowing base was $50.0 million, $44.3 million was outstanding at a weighted average interest rate of 7.585% and the unused borrowing base was $5.7 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 October 31, 2007, the balance outstanding under the SCA was $46.3 million with a weighted average interest rate of 7.65%.

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, 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 September 30, 2007, we had a $100 million five-year term loan facility with Bank of Montreal (the "TLA") and certain other financial institutions party thereto with a current interest rate of 9.875%. The TLA was amended on July 25, 2007, increasing the principal amount from $80 million and extending the prepayment penalty date to July 25, 2008.

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 amended SCA and TLA require TXCO and its subsidiaries to meet a maximum consolidated leverage ratio of 3.00 to 1.00, a minimum current assets to current liabilities ratio of 1.00 to 1.00, 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 to declare all amounts outstanding under the SCA and TLA to be immediately due and payable.

Outlook: We believe the Bank Credit Facilities, 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 2007. We expect to further increase our borrowing base commensurate with the expected growth of our proved oil and gas reserves throughout the base term of the 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.

Risk Management Activities -- Commodity Hedging Contracts: Due to the volatility of oil and natural gas prices and requirements under our Bank Credit Facilities, we periodically 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." When used, 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 elected to account for certain of our derivative contracts as investments as permitted 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, and is reclassified to income as the hedged transactions occur. The hedges are highly effective, and therefore, no hedge ineffectiveness has been recorded.

In accordance with the terms of our Bank Credit Facilities, as amended, we entered into derivative agreements in August 2007. At September 30, 2007, collars were in place covering approximately 50% of our projected crude oil and natural gas sales over the next 3.5 years. See Note 5 to our consolidated financial statements for further information.

Sources and Uses of Cash: At December 31, 2006, our cash reserves were $3.9 million. During the first nine months of 2007, cash provided by operating activities was $27.3 million. In addition, borrowings under the bank credit facilities of $164.8 million, proceeds from installment obligations of $0.3 million, and proceeds from the exercise of options totaling $0.4 million, resulted in total cash available of $196.7 million for use in meeting our ongoing operational and development needs.

Payments on bank credit facilities during the first nine months of 2007 totaled $22.9 million in principal, while payments on installment debt were $0.4 million, and interest payments on debt were $4.3 million. There were no federal income taxes paid during 2007. We applied $96.0 million for the purchase of Output, $68.1 million to fund the ongoing development of our oil and gas producing properties, and $2.3 million for the purchase of other equipment.

We ended the first nine months of 2007 with positive working capital of $7.2 million, compared to $2.7 million at December 31, 2006 adjusted for the impact of the derivative liabilities on current assets and liabilities. At September 30, 2007, our current ratio was 1.23 to 1 compared to 1.17 to 1 at year-end 2006, with the same adjustment. Working capital at September 30, 2007, including the net $1.0 million current liability associated with our derivatives, was $6.0 million, while the current ratio was 1.19 to 1. At year-end 2006, including the $0.4 million of derivative current liabilities, working capital was $2.3 million, while the current ratio was 1.14 to 1.

We completed the first nine months of 2007 with an unused borrowing base of $5.7 million under the Bank Credit Facilities. Net cash provided by operating activities for the first nine months of 2007 was $27.3 million, compared to $14.0 million in the first nine months of 2006. Before changes in operating assets and liabilities, net cash provided by operating activities during the first nine months of 2007 was $32.5 million compared to $21.5 million for the same 2006 period. Changes in operating assets and liabilities include increases or decreases in current receivables, payables and prepaid expenses from the prior year-end balances.

Results of Operations

The following table highlights the change for 2007 from the comparable periods in 2006:

Selected Income Statement Items	**Three Months**				**Nine Months**			
for the periods ending September 30	**$ thousands**		**%**		**$ thousands**		**%**	
Oil and gas revenues	+	6,945	+	38.4	+	8,484	+	19.1
Lease operating expense	+	1,321	+	72.7	+	4,707	+	88.3
Depreciation, depletion & amortization	+	7,093	+	156.3	+	14,325	+	131.5
Income from operations	-	2,002	-	23.9	-	13,434	-	74.1
Net income / loss	-	4,009	-	62.8	-	12,471		n/m

n/m - % change not meaningful due to a move from income to loss for the period

The following table summarizes the change for 2007 from the comparable periods in 2006:

Change in Gas Gathering Results:	**Three Months**				**Nine Months**			
for the periods ending September 30	**$ thousands**		**%**		**$ thousands**		**%**	
Gas gathering revenues	-	284	-	8.1	-	3,858	-	30.3
Gas gathering operations expense	-	123	-	3.5	-	3,260	-	25.2
Gross margin	-	161	-	365.9	-	598	-	299.0
Operational data:								
Total sales volumes (mmbtu)	-	35,822	-	8.8	-	474,248	-	32.6
Average sales price ($ per mmbtu)	-	0.13	-	1.6	+	0.05	+	0.6

Three Months Ended September 30, 2007, Compared with Three Months Ended September 30, 2006:

Revenues

The 38.4% increase in oil and gas revenue is primarily due to the Output acquisition (26.2% of third quarter 2007 revenue) along with higher average realized prices for crude oil and higher volumes for both products, partially offset by lower average realized prices for natural gas. Sales volumes increased 37.3% on a mcfe basis. Natural gas sales volumes were up 134.1% due to Output volumes, partially offset by reductions in Maverick Basin gas volumes reflecting normal maturing gas well decline curves and our emphasis on drilling oil wells this year. Oil sales volumes increased 18.7% primarily due to Glen Rose Porosity wells put on production since September 30, 2006. Excluding the impact of hedging, average realized sales prices for natural gas were down 3.6%, while those for crude oil were up 7.6%. Derivative gains on hedges of natural gas were offset by derivative losses on hedges of crude oil during the third-quarter 2007. Prior year revenues were not impacted by hedging, since the derivatives in place for transactions in that time period were treated as investments.

Lease Operations ("LOE")

The 72.7% increase reflects costs related to wells acquired in the Output acquisition (25.6% of current LOE), as well as 41 net oil wells and two net gas wells placed on production since September 30, 2006, and increasing costs due to greater demand for third-party services in the field.

Exploration Expenses

The 16.0% decrease primarily reflects lower delay rentals.

Gas Gathering

The 8.1% decrease in gas gathering revenues (and 3.5% decrease in related expenses) reflects lower volumes for third-party natural gas sales and lower transportation and other revenues. The impact was partially offset by higher natural gas liquids sales at higher realized prices. 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 its gas rather than sell it through TXCO.

Impairment

Over accruals for our impairment provision in the prior two quarters were reversed during the current quarter. No impairment was recorded in the comparable prior-year quarter.

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

The 156.3% increase is due to the Output acquisition (22.0% of DD&A), higher finding costs, depletion rates and costs related to new wells placed on production over the last year.

General and Administrative ("G&A")

The $1.0 million increase was primarily due to the Output acquisition (16.0% of G&A) and higher salaries. G&A expense as a percentage of revenue increased to 11.0%, from 9.8% last year. During the second quarter 2007 G&A as a percentage of revenue was 13.8%.

Derivative Gain / Loss

No mark-to-market ("MTM") or settlement gains or losses were recorded in third-quarter 2007 as our current hedges are designated as cash flow hedges. Settlements on cash flow hedges are reflected in revenues. For the MTM hedges in the prior year quarter, a net pre-tax hedging gain of $0.4 million was recorded, reflecting a MTM gain partially offset by settlement costs.

Interest Expense

The $3.2 million increase was due to our long-term financing related primarily to the Output acquisition.

Income Tax Expense

Our effective tax rate was 23.3%, down from 28.0% in the prior year period. Net income tax expense was down due to changes in the Texas Margin (franchise) tax laws.

Nine Months Ended September 30, 2007, Compared with Nine Months Ended September 30, 2006:

Revenues

The 19.1% increase in oil and gas revenue is primarily due to the Output acquisition (24.0% of revenues) along with higher crude oil and natural gas sales volumes and higher average sales prices for crude oil, partially offset by losses on derivatives designated as cash flow hedges and lower average realized prices for natural gas. Sales volumes increased 27.4% on a mcfe basis. Oil sales volumes increased 15.6% primarily due to Glen Rose Porosity wells put on production since September 30, 2006. Natural gas volumes were up 75.6%, reflecting volumes from Output properties partially offset by normal maturing gas well decline curves. Additionally, due to our current focus on drilling oil wells in the Maverick Basin, we are not replacing gas-specific reserves at the present time. Excluding the impact of hedging, average realized sales prices for oil were down 0.5%, while those for natural gas were down 3.4%. Derivative losses reduced revenues by $1.7 million for the first nine months of 2007, of which $1.5 million was a non-cash charge allocating the cost of the 2005 termination of gas hedges for transactions in this period. Prior year revenues were not impacted by hedging, since the derivatives in place for transactions in that time period were mark-to-market hedges.

Lease Operations ("LOE")

The 88.3% increase reflects the Output acquisition (24.5% of LOE) and costs related to 41 net oil wells and 2 net gas wells placed on production since September 30, 2006, and increasing costs due to greater demand for third-party services in the field.

Exploration Expenses

The 3.9% decrease primarily reflects lower delay rentals.

Gas Gathering

The 30.3% decrease in gas gathering revenues (and 25.2% decrease in related expenses) is primarily due to lower volumes for third-party natural gas 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 its gas rather than sell it through TXCO.

Impairment

Impairment accruals decreased 73.6% primarily due to lower anticipated impairment rates on existing wells.

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

Depreciation, depletion and amortization increased 131.5% due to the Output acquisition (19.7% of DD&A), higher finding costs, depletion rates and costs related to new wells placed on production over the last year.

General and Administrative ("G&A")

The $2.3 million increase was primarily due to the Output acquisition (18.1% of G&A), and higher salaries. G&A expense as a percentage of revenue increased to 12.9%, from 9.9% last year.

Derivative Gain / Loss

No mark-to-market ("MTM") or settlement gains or losses were recorded in 2007 as our current derivatives are designated as cash flow hedges. Settlements on cash flow hedges are reflected in revenues. For the MTM hedges in the prior year quarter, a net pre-tax hedging loss of $0.8 million was recorded, primarily reflecting settlement costs.

Interest Expense

The $6.2 million increase was due to our long-term financing related to the Output acquisition.

Income Tax Expense

For the current period, our income tax provision was a tax benefit compared to a tax expense in the prior period. Due to changes in the Texas Margin (franchise) tax laws, effective tax expense from prior periods is being reversed in the current period. This has increased the effective rate of our tax benefit in the current period. Our effective tax rate was 53.8% (benefit), compared to 33.2% (expense) in the prior year period.

Drilling Activities

We drilled or participated in drilling 76 wells in the first nine months of 2007. Of these wells, 62 were in the Maverick Basin, three were in the Williston Basin, one each in the Marfa Basin and Fayette County, and nine were on Output holdings. In October 2007, we spudded five additional wells. At October 31, 2007, of the 81 total wells that we participated in this year, 45 were on production, 26 were in completion or being evaluated for recompletion, and nine remained drilling, while one was plugged and abandoned. Additionally, three wells that were in progress at year-end 2006, and one spud before our acquisition of Output, were placed on production in 2007. We have focused primarily on the Glen Rose and San Miguel formations thus far in 2007. By comparison, we participated in 54 wells during the first nine months of 2006. The following table shows net daily sales for the periods presented:

	Quarter Ended			% Change from	
Average net daily sales volumes :	**September 30, 2007**	**June 30, 2007**	**September 30, 2006**	**2nd Qtr 2007**	**3rd Qtr 2006**
Oil, bopd	3,125	2,644	2,633	+18.2	+18.7
Natural gas, mcfd	7,087	7,082	3,027	-	+134.1
Oil equivalent, boed	4,306	3,825	3,137	+12.6	+37.3

Normal production declines were experienced on natural gas wells in the first nine months of 2007 and only two new gas wells were put on production in the Maverick Basin to offset declines on maturing wells. Additionally, four gas wells were put on production on former Output acreage. Oil sales during the first nine months of 2007 did not reach their potential for three major reasons:

- heavy rains in our Maverick Basin operating area,
- impact of fourth-quarter 2006 drilling technique issues, and
- unscheduled third-party oil pipeline repairs.

<u>Maverick Basin</u>

There are six rigs under contract to facilitate drilling or re-entry of about 90 wells during 2007. The drilling rig we purchased in March 2006 was placed in service in January of this year and is being used primarily on wells in which TXCO has a 100% working interest ("WI"). Earlier this year, 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, while the other is stacked.

Glen Rose Porosity ("GRP") - During the first nine months of 2007, we drilled or re-entered 32 Porosity wells, up from 28 in the same period of 2006. One additional Porosity well was begun in October 2007. As of October 31, 2007, of the 33 total 2007 Porosity wells, 22 are on production, nine are in completion, and two continue drilling. GRP average daily sales for third-quarter 2007 were 2,253 bopd, compared to 1,775 bopd for the preceding quarter and 2,341 bopd for the comparable prior-year quarter. See the discussion above for causes of the decline in oil production from the prior year.

GRP targets represent more than half of our 2007 CAPEX budget. We currently plan to drill or re-enter over 35 wells in the Porosity during 2007. We have engaged Schlumberger to conduct a comprehensive reservoir optimization study. The study is focused on multiple aspects of the GRP project, including the establishment of higher reserve levels, higher recovery rates, evaluating secondary recovery opportunities and overall operating efficiencies, and should be completed next spring.

Glen Rose Shoal/Reefs - During the first nine months of 2007, we drilled three shoal and three reef wells. As of October 31, 2007, two are producing natural gas, one is in completion, while two are being evaluated for re-completion, and one was sidetracked to the Georgetown formation, where it began oil production in October. Two wells targeting a Glen Rose reef or shoal were started in the first nine months of 2006.

Glen Rose average daily sales for third-quarter 2007, excluding Porosity production, were 7 bopd and 2.2 mmcfd, compared to 1 bopd and 2.3 mmcfd for the prior quarter and 10 bopd and 2.6 mmcfd for the prior-year quarter. We currently plan to drill 12 shoal/reef wells during 2007.

Georgetown - We started five Georgetown wells in the first nine months of 2007. Two of these wells are producing oil, while the other three are awaiting completion as of October 31, 2007. As previously mentioned, one well that originally targeted a Glen Rose Reef was sidetracked to the Georgetown formation and began producing crude oil in October. For comparison, we participated in four Georgetown wells in the comparable prior year period. Our 2007 CAPEX budget includes five Georgetown wells. Georgetown average daily sales for third-quarter 2007 were 18.7 bopd and 93 mcfd, compared to 18.0 bopd and 110 mcfd for the preceding quarter, and 31.2 bopd and 122 mcfd for the prior-year quarter.

San Miguel - San Miguel average daily sales for third-quarter 2007 were 207.3 bopd, compared to 218.6 bopd for the preceding quarter, and 170.5 bopd for the prior-year quarter. We started 10 San Miguel wells during the first nine months of 2007. One additional San Miguel well was begun during October. As of October 31, 2007, nine wells are producing oil, one was plugged and abandoned, and one continues drilling. We began 15 San Miguel wells in the prior year period. Our CAPEX budget calls for 11 San Miguel wells in 2007.

San Miguel Oil Sands - The two-well cyclic steam pilot test of the Oil Sands formation with our partner, Pearl Exploration and Production Ltd. ("Pearl"), involves a steam injection, soak and production cyclical process designed to heat the oil (0 degree API gravity) and allow it to be produced. After the third injection cycle, the formation temperature has increased to approximately 365 degrees Fahrenheit. We have repaired some mechanical problems with pumping equipment and begun the fourth injection cycle. Oil produced from the project was sent to prospective refiners to establish a pricing differential. We have received a preliminary estimate that our heavy oil will receive about a $15 per barrel discount to West Texas Intermediate prices, comparable to prices for similar quality crudes produced elsewhere. Additional steam generation equipment on order for the expansion of this pilot is expected to be delivered in January 2008. We are concluding reservoir simulation studies regarding the use of horizontal wells and cyclic steam and expect to have three to five additional wells drilled prior to the arrival of the steam generation equipment.

Reservoir simulation studies are progressing on a second pilot with 8 to 16 wells updip of the existing pilot. We expect the second pilot will accelerate the overall project and establishment of reserves. We have ordered steam generation equipment for this pilot and currently anticipate that it will probably be delivered to location in April and May of next year. We now anticipate that this pilot will begin late in the second quarter of 2008 due to the delay in delivery of steam generators. We plan to use fracture-assisted steamflood technology recovery ("FAST") methods with a few modifications to compare its results with the cyclical process used on the first pilot. Conoco reported recovering over 50% of the tar in place on two pilots conducted in the early 1980s in the Oil Sands. TXCO has a 50% WI and serves as operator with Pearl on about one-half the lease block but TXCO owns a 100% WI in the remainder. We believe that our net interest in these oil sands amounts to roughly two to three billion barrels of total oil in place.

Heavy Oil - Separately, we have begun a shallow pilot in an area (100% WI) that our geologists and engineers estimate contains 100 million barrels of heavy (10- to 14-degree API gravity) oil at 100-300 feet in depth. Two parallel horizontal wells with 2,000 feet laterals have been drilled through the zone, as well as five adjacent vertical wells. This pilot anticipated the use of an unusual, hydrogen peroxide steam generation technique that reportedly would have greatly improved the economics of the project since it did not require water nor natural gas to generate the steam. Unfortunately, the providers of the technique have been unable to meet our timetables. Consequently, we will seek conventional steam generation equipment for the project. We hope to begin injecting steam as soon as possible after we receive all regulatory approvals. Costs incurred to date on this project are about $0.5 million.

Pearsall - The horizontal well (50%WI) drilled with our partner, EnCana Oil & Gas (USA) Inc., in the Maverick Basin's James formation is currently producing approximately 150 mcfd and is continuing to improve. The well is intended to be drilled horizontally in the Pearsall interval once the completion in the James is concluded. Two wells were spudded targeting the Pearsall formation during third-quarter 2007 (100% WI). One well is testing the Pearsall vertically and is currently flowing 3,000 mcfd with 7,200 psi flowing tubing pressure. Operations continue to clean out the 18.2 pound-per-gallon mud left in the open hole. An eight-mile pipeline will have to be laid to market this gas. The other well is a re-entry of an old wellbore that flow tested the Pearsall at a rate of over 1,000 mcfd in the late 1970s. The well is awaiting completion after being drilled horizontally. Additionally, a third well was spudded in October targeting the Pearsall formation that continues drilling.

In October 2007, we entered into a joint exploration agreement with EnCana to drill three horizontal Pearsall wells on their acreage in the Maverick Basin prior to July 31, 2008, carrying EnCana for a 50% WI in each well. As part of the agreement, we acquired 100% of their interests above the Pearsall formation and will earn a 50% WI in the deep rights in 1,280 acres around each well. We have the option but not the obligation to drill four additional horizontal Pearsall wells prior to July 31, 2009, carrying EnCana for 50% WI in each well and earning a 50% WI in the deep rights in 5,760 acres around each well. We have the additional option, but not the obligation, to carry EnCana for a 25% WI in an additional 16-20 horizontal Pearsall wells, depending upon well costs. Consequently, we have the option to earn 50% of the deep rights in the remaining acres in the 250,000 acre lease block.

Marfa Basin

We fracture stimulated the Simpson 1 well in the Barnett shale interval during the third quarter 2007. We installed a tiltmeter array around the well prior to the fracture stimulation. Data from this array will provide micro-seismic information on the direction and distance of the fracture, enabling us to determine the best drilling plan for a future horizontal well. Continental Resources Inc., our 50% partner in this acreage who serves as operator for the lease block, elected to go non-consent on this fracture procedure. TXCO initiated and monitored this fracture stimulation. The well currently is producing fracturing fluids, flowing back at rates of about 100 bwpd and 140 mcfd. As water production decreases, we expect that gas production will increase.

Output Properties

Operations are ongoing on former Output properties. Six new wells and four re-entries have been spudded since we acquired Output on April 2. At October 31, 2007, four of these wells are producing, three are awaiting completion and three continue drilling. The producing wells include two sidetracks on South Marsh Island Block 281 (6.8% WI and 5.2% WI), one well in South Texas (4.3% WI), and one well in Oklahoma (1.6% WI). Additionally, one Oklahoma well (12%WI) spud before our acquisition was put on production for natural gas in July. We expect to participate in about 30 wells this year on prospects acquired through Output.

The first horizontal well to the undeveloped Glen Rose shoals that we have identified in the Fort Trinidad Field in East Texas is currently drilling. This is our first, internally generated prospect on Output acreage. We have identified 40 prospective B shoal locations in the Field, where we have 8,300 net acres under lease.

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 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. 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, 2006. 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. Our 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, 2007, we had borrowings under our SCA of $44.3 million at a weighted average interest rate of 7.585% per annum, and under the TLA of $100 million at a rate of 9.875%. Assuming an increase in either the LIBOR or prime rate of interest of 100 basis points, interest expense would increase by approximately $1,443,000 per year. The interest rate variability on all other debt would not have a material adverse effect on our financial position.

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 periodically 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 through 2007 production. These derivatives expired on April 30, 2007. TXCO entered into derivative agreements in August 2007 to cover approximately 50% of the Company's and its subsidiaries' aggregate projected oil and gas production anticipated to be sold in the ordinary course of its business during the upcoming three-year period, in accordance with terms of our term loan and revolving credit facilities. Please refer to Note 5 to the consolidated financial statements included herein for additional information.

The following is a list of derivative contracts outstanding as of September 30, 2007:

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Volumes Per Month
Natural Gas (1):					
08/07	Collar	09/01/2007	12/31/2007	$6.50-$6.85	75,000 mcf
08/07	Collar	09/01/2007	12/31/2007	$6.50-$6.80	25,000 mcf
08/07	Collar	01/01/2008	12/31/2008	$6.50-$10.40	65,000 mcf
08/07	Collar	01/01/2008	12/31/2008	$6.50-$10.35	20,000 mcf
08/07	Collar	01/01/2009	12/31/2009	$6.50-$11.65	55,000 mcf
08/07	Collar	01/01/2009	12/31/2009	$6.50-$11.60	15,000 mcf
08/07	Collar	01/01/2010	06/30/2010	$6.50-$11.65	45,000 mcf
08/07	Collar	01/01/2010	06/30/2010	$6.50-$11.60	15,000 mcf
Crude Oil (2):					
08/07	Collar	09/01/2007	12/31/2007	$65-$76.10	21,000 Bbl
08/07	Collar	09/01/2007	12/31/2007	$65-$75.50	9,000 Bbl
08/07	Collar	01/01/2008	12/31/2008	$65-$74.00	6,000 Bbl
08/07	Collar	01/01/2008	12/31/2008	$65-$73.80	14,000 Bbl
08/07	Collar	01/01/2009	12/31/2009	$65-$73.00	4,000 Bbl
08/07	Collar	01/01/2009	12/31/2009	$65-$72.80	11,000 Bbl
08/07	Collar	01/01/2010	06/30/2010	$65-$73.00	4,000 Bbl
08/07	Collar	01/01/2010	06/30/2010	$65-$72.80	8,000 Bbl

(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.

For additional information, see also our Annual Report on Form 10-K for the year ended December 31, 2006, "Part II, 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, 2007, 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.

Except for the potential changes noted in the following paragraph relating to the Output acquisition, 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.

In April 2007, we completed the acquisition of Output Exploration, LLC. We are in the process of transferring all accounting for the new acquisition to our headquarters and into our existing internal control processes. The integration will lead to changes in these controls in future fiscal periods but we do not expect these changes to materially affect our internal controls over financial reporting. Consistent with published guidance of the SEC, our management excluded the acquired companies from the scope of its assessment of internal control over financial reporting as of September 30, 2007. Total assets and total revenues from the acquisition represented approximately 38.6% and 20.7%, respectively, of the related consolidated financial statement amounts of TXCO as of the nine months ended September 30, 2007.

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, 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

Please see the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

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

The following table summarizes our stock repurchase activity during 2007:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total number of shares Purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs ($ million)
01/1-31/2007	18,564	$ 11.77	-	$ -
02/1-28/2007	55	$ 11.46	-	$ -
03/1-31/2007	-	$ -	-	$ -
04/1-30/2007	-	$ -	-	$ -
05/1-31/2007	-	$ -	-	$ -
06/1-30/2007	-	$ -	-	$ -
07/1-31/2007	-	$ -	-	$ -
08/1-31/2007	-	$ -	-	$ -
09/1-30/2007	-	$ -	-	$ -

(1) During the first quarter of 2007, the Company acquired 18,619 shares of common stock that employees presented to the Company to satisfy withholding taxes in connection with the vesting of restricted stock awards. The Company has made no other purchases of its own stock during 2007.

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, 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, 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.
d)	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.

TXCO RESOURCES INC.
(Registrant)

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

Date: November 9, 2007