SWIFT ENERGY CO
Form 10-Q
November 02, 2007

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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2007

Commission File Number 1-8754

SWIFT ENERGY COMPANY

TEXAS	20-3940611
(State of Incorporation)	(I.R.S. Employer Identification No.)
16825 Northchase Drive, Suite 400 Houston, Texas	77060
(Address of principal executive offices)	(Zip Code)

(281)-874-2700
(Registrant's telephone number, including area code)

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, and (2) has been subject to such filing requirements for the past 90 days.
Yesþ No o

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	þ	Accelerated filer	o	Non-accelerated filer	o

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

Indicate the number of shares outstanding of each of the Issuer's classes of common stock, as of the latest practicable date.

Common Stock ($.01 Par Value) (Class of Stock)	30,105,226 Shares (Outstanding at October 31, 2007)

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2007
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Item 1.
Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	September 30, 2007	December 31, 2006
	(Unaudited)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,711	$ 1,058
Accounts receivable-		
Oil and gas sales	58,409	63,935
Joint interest owners	1,177	1,844
Other Receivables	1,133	1,231
Deferred tax asset	---	2,383
Other current assets	46,466	22,122
Total Current Assets	118,896	92,573
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	2,569,223	2,264,832
Unproved properties	107,689	112,136
	2,676,912	2,376,968
Furniture, fixtures, and other equipment	34,633	28,041
	2,711,545	2,405,009
Less – Accumulated depreciation, depletion, and amortization	(1,073,797)	(921,697)
	1,637,748	1,483,312
Other Assets:		
Debt issuance costs	7,527	7,382
Restricted assets	2,398	2,415
	9,925	9,797
	$ 1,766,569	$ 1,585,682
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 67,212	$ 74,425
Accrued capital costs	60,925	55,282
Accrued interest	8,577	8,764
Undistributed oil and gas revenues	2,071	7,504
Total Current Liabilities	138,785	145,975
Long-Term Debt	400,000	381,400
Deferred Income Taxes	279,958	224,967
Asset Retirement Obligation	35,141	33,695
Lease Incentive Obligation	1,549	1,728
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---	---
	305	302

Common stock, $.01 par value, 85,000,000 shares authorized, 30,518,791 and 30,170,004 shares issued, and 30,083,821 and 29,742,918 shares outstanding, respectively		
Additional paid-in capital	401,980	387,556
Treasury stock held, at cost, 434,970 and 427,086 shares, respectively	(7,420)	(6,125)
Retained earnings	516,271	415,868
Accumulated other comprehensive income, net of income tax	---	316
	911,136	797,917
	$ 1,766,569	$ 1,585,682

See accompanying notes to condensed consolidated financial statements.

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Condensed Consolidated Statements of Income (Unaudited)
Swift Energy Company and Subsidiaries
(in thousands, except per share amounts)

	Three Months Ended		Nine Months Ended	
	09/30/07	09/30/06	09/30/07	09/30/06
Revenues:				
Oil and gas sales	$ 179,525	$ 173,369	$ 488,228	$ 453,316
Price-risk management and other, net	1,695	90	2,254	3,489
	181,220	173,459	490,482	456,805
Costs and Expenses:				
General and administrative, net	10,265	8,018	29,295	23,323
Depreciation, depletion and amortization	53,568	45,868	150,894	120,151
Accretion of asset retirement obligation	388	172	1,170	666
Lease operating costs	21,530	12,926	59,960	45,844
Severance and other taxes	20,152	18,490	55,465	49,211
Interest expense, net	5,700	5,776	19,742	17,436
Debt retirement cost	---	---	12,765	---
	111,603	91,250	329,291	256,631
Income Before Income Taxes	69,617	82,209	161,191	200,174
Provision for Income Taxes	27,335	31,397	59,811	73,879
Net Income	$ 42,282	$ 50,812	$ 101,380	$ 126,295
Per Share Amounts				
Basic: Net Income	$ 1.41	$ 1.74	$ 3.39	$ 4.33
Diluted: Net Income	$ 1.38	$ 1.68	$ 3.32	$ 4.20
Weighted Average Shares Outstanding	30,051	29,252	29,937	29,161

See accompanying notes to condensed consolidated financial statements.

Condensed Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2005	$ 295	$ 365,086	$ (6,446)	$ (5,850)	$ 254,303	$ (70)	$ 607,318
Stock issued for benefit plans (22,358 shares)	-	714	321	-	-	-	1,035
Stock options exercised (652,829 shares)	7	11,831	-	-	-	-	11,838
Adoption of SFAS No. 123R	-	(5,875)	-	5,850	-	-	(25)
Excess tax benefits from stock-based awards	-	4,811	-	-	-	-	4,811
Employee stock purchase plan (22,425 shares)	-	671	-	-	-	-	671
Issuance of restricted stock (35,776 shares)	-	-	-	-	-	-	-
Amortization of stock compensation	-	10,318	-	-	-	-	10,318
Comprehensive income:							
Net income	-	-	-	-	161,565	-	161,565
Other comprehensive income	-	-	-	-	-	386	386
Total comprehensive income							161,951
Balance, December 31, 2006	$ 302	$ 387,556	$ (6,125)	$ -	$ 415,868	$ 316	$ 797,917
Stock issued for benefit plans (32,817 shares) (2)	-	953	471	-	-	-	1,424
Stock options exercised (148,665 shares) (2)	1	1,901	-	-	-	-	1,902
Purchase of treasury shares (40,701 shares) (2)	-	-	(1,766)	-	-	-	(1,766)
Adoption of FIN 48 (2)	-	-	-	-	(977)	-	(977)
Employee stock purchase plan (17,678 shares) (2)	-	619	-	-	-	-	619

Issuance of restricted stock (182,444 shares) (2)	2	(2)	-	-	-	-	-
Amortization of stock compensation (2)	-	10,953	-	-	-	-	10,953
Comprehensive income:							
Net income (2)	-	-	-	-	101,380	-	101,380
Other comprehensive loss (2)	-	-	-	-	-	(316)	(316)
Total comprehensive income (2)							101,064
Balance, September 30, 2007 (2)	$ 305	$ 401,980	$ (7,420)	$ -	$ 516,271	$ -	$ 911,136

(1)$.01 par value.
(2)Unaudited.

See accompanying notes to condensed consolidated financial statements.

Condensed Consolidated Statements of Cash Flows (Unaudited)
Swift Energy Company and Subsidiaries
(in thousands)

	Nine Months Ended September 30,	
	2007	2006
Cash Flows from Operating Activities:		
Net income	$ 101,380	$ 126,295
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	150,894	120,151
Accretion of asset retirement obligation	1,170	666
Deferred income taxes	59,688	67,169
Stock-based compensation expense	7,783	5,057
Debt retirement cost – cash and non-cash	12,765	---
Other	(127)	(3,677)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	6,193	(14,548)
Increase in accounts payable and accrued liabilities	1,644	7,404
Increase (decrease) in income taxes payable	(884)	338
Increase (decrease) in accrued interest	(187)	1,828
Net Cash Provided by Operating Activities	340,319	310,683
Cash Flows from Investing Activities:		
Additions to property and equipment	(335,898)	(295,502)
Proceeds from the sale of property and equipment	219	20,336
Net cash received as operator of partnerships and joint ventures	485	855
Other	---	(31)
Net Cash Used in Investing Activities	(335,194)	(274,342)
Cash Flows from Financing Activities:		
Proceeds from long-term debt	250,000	---
Payments of long-term debt	(200,000)	---
Net payments of bank borrowings	(31,400)	---
Net proceeds from issuances of common stock	2,521	4,289
Excess tax benefits from stock-based awards	---	1,483
Purchase of treasury shares	(1,766)	---
Payments of debt retirement costs	(9,376)	---
Payments of debt issuance costs	(4,451)	---
Net Cash Provided by Financing Activities	5,528	5,772
Net Increase in Cash and Cash Equivalents	$ 10,653	$ 42,113
Cash and Cash Equivalents at Beginning of Period	1,058	53,005
Cash and Cash Equivalents at End of Period	$ 11,711	$ 95,118

Supplemental Disclosures of Cash Flows Information:

Cash paid during period for interest, net of amounts capitalized	$	19,008	$	14,721
Cash paid during period for income taxes	$	1,007	$	6,373

See accompanying notes to condensed consolidated financial statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company ("Swift Energy" or the "Company") and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

Holding Company Structure

In December 2005, we implemented a holding company structure pursuant to Texas and federal law in a manner designed to be a non-taxable transaction. The new parent holding company assumed the Swift Energy Company name and continued to trade on the New York Stock Exchange. The purposes of this new holding company structure are to separate Swift Energy's domestic and international operations to better reflect management practices, to improve our economics, and to provide greater administrative and organizational flexibility. Under the new organizational structure, four new subsidiaries were formed with the Texas parent holding company wholly owning three Delaware subsidiaries, which in turn wholly own Swift Energy's operating subsidiaries. Swift Energy Operating, LLC is the operator of record for Swift Energy's domestic properties. Swift Energy's name, charter, bylaws, officers, board of directors, authorized shares and shares outstanding remain substantially identical. Our international operations continue to be conducted through Swift Energy International, Inc. Swift Energy amended its bank credit agreement, debt indentures and various other plans and documents to accommodate the internal reorganization, but our day-to-day conduct of business was not impacted. Accordingly, there was no impact on our financial position or results of operations.

Property and Equipment

We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the nine months ended September 30, 2007 and 2006, such capitalized internal costs totaled $23.0 million and $20.7 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the nine months ended September 30, 2007 and 2006, capitalized interest on unproved properties totaled $7.2 million and $6.6 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, natural gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment, held at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between two and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (G&G) costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test

At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). We did not have any hedges in place at September 30, 2007. This calculation is performed on a country-by-country basis.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization ("DD&A") is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Swift Energy Company and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas, as well as onshore oil and natural gas reserves in New

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

Zealand. Our undivided interests in natural gas processing plants are accounted for using the proportionate consolidation method, whereby our proportionate share of assets, liabilities, revenues, andexpenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Revenue Recognition

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Beginning in 2007, processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are recorded in “Lease operating costs” prior to that time these costs were deducted from revenues. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in “Accounts payable and accrued liabilities” on the accompanying balance sheet. Natural gas balancing receivables are reported in “Other current assets” on the accompanying balance sheet when our ownership share of production exceeds sales. As of September 30, 2007, we did not have any material natural gas imbalances.

Reclassification of Prior Period Balances

Certain reclassifications have been made to prior period amounts to conform to the current year presentation.

Accounts Receivable

We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both September 30, 2007 and December 31, 2006, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balances on the accompanying balance sheets.

Inventories

We value inventories at the lower of cost or market. Cost of crude oil inventory is determined using the weighted average method and all other inventory is accounted for using the first in, first out method (“FIFO”). The major categories of inventories, which are included in “Other current assets” on the accompanying balance sheets, are shown as follows:

(in thousands)	**Balance at September 30, 2007**	**Balance at December 31, 2006**
Materials, Supplies and Tubulars	$ 11,876	$ 10,611
Crude Oil	738	474
Total	$ 12,614	$ 11,085

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,estimates of insurance recoveries related to property damage,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Income Taxes

Under SFAS No. 109, “Accounting for Income Taxes,” deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to our deferred tax liability. This is also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We do not expect to recognize significant increases or decreases in unrecognized tax benefits during the year ended December 31, 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2006 and September 30, 2007 no interest or penalties relating to income taxes have been recognized.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward remain subject to examination by tax authorities. Our Texas franchise tax returns for 2005 and prior years have been audited by the Texas State Comptroller. There are no unresolved items related to those audits. No other state returns are significant to our financial position. Our New Zealand income tax returns from 2002 forward remain subject to examination by the local tax authority.

In the third quarter of 2007 we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance is due to changes in the Company’s property disposition plans and increased income tax expense by $2.6 million in that period.

Accounts Payable and Accrued Liabilities

Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at September 30, 2007 and December 31, 2006 are liabilities of approximately $11.5 million and $13.9 million, respectively, representing the amount by which checks issued, but not presented by vendors to Swift Energy's banks for collection, exceeded balances in the applicable disbursement bank accounts.

Accumulated Other Comprehensive Income, Net of Income Tax

We follow the provisions of SFAS No. 130, “Reporting Comprehensive Income,” which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of Swift Energy. At September 30, 2007, we did not record any derivative gains or losses in “Accumulated other comprehensive income, net of income tax” on the accompanying balance sheet. The components of accumulated other comprehensive income and related tax effects were as follows:

(in thousands)	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive income at December 31, 2006	$ 503	$ (187)	$ 316
Change in fair value of cash flow hedges	(184)	68	(116)
Effect of cash flow hedges settled during the period	(319)	119	(200)
Other comprehensive income at September 30, 2007	$ ---	$ ---	$ ---

Total comprehensive income was $42.1 million and $52.2 million for the third quarter of 2007 and 2006, respectively. Total comprehensive income was $101.1 and $127.3 million for the first nine months of 2007 and 2006, respectively.

Price-Risk Management Activities

Swift Energy follows SFAS No. 133, which requires that changes in the derivative’s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During the third quarters of 2007 and 2006, we recognized a net gain of $1.0 million and a net loss of $0.4 million, respectively, relating to our derivative activities. During the first nine months of 2007 and 2006, we recognized a net gain of $0.3 million and a net gain of $1.6 million, respectively, relating to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. At September 30, 2007, we had not recorded any derivative gains or losses in “Accumulated other comprehensive income, net of income tax” on the accompanying balance sheet as we did not have any hedges in place at that time. This line item on the balance sheet represents the change in fair value for the effective portion of our hedging transactions that are qualified as cash flow hedges. The amount of ineffectiveness reported in “Price-risk management and other, net” for the first nine months of 2007 and 2006 was not material.

When we entered into the transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers. Supervision Fees

Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to "General and administrative, net." All of ourdomestic supervision fees are based on COPAS determined rates; the remainder (less than 2% for each period presented) is attributable to our New Zealand operations and is based on agreements that are similar to COPAS. The amount of supervision fees charged in 2006 and 2007 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate were $8.0 million and $6.4 million in the first nine months of 2007 and 2006, respectively.

Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the related asset is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depleted on a unit-of-production basis over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the full cost pool. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003. The following provides a roll-forward of our asset retirement obligation:

(in thousands)	**2007**	**2006**
Asset Retirement Obligation recorded as of January 1	$ 34,460	$ 19,356
Accretion expense for the nine months ended September 30	1,170	666
Liabilities incurred for new wells and facilities construction	321	553
Reductions due to sold, or plugged and abandoned wells	---	(203)
Increase (decrease) due to currency exchange rate fluctuations	65	(22)
Asset Retirement Obligation as of September 30	$ 36,016	$ 20,350

At September 30, 2007 and December 31, 2006, approximately $0.9 million and $0.8 million of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying balance sheets.

New Accounting Pronouncements

Effective January 1, 2007, Swift Energy adopted FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109" ("FIN 48"). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." See additional discussion of FIN 48 in the Income Taxes section of the footnotes. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to our deferred tax liability.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. We have not yet determined what impact, if any, this statement will have on our financial position or results of operations.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, for additional information related to these share-based compensation plans.

Effective January 1, 2006, Swift Energy adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), “Share-Based Payment” (SFAS No. 123R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees” (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants.

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for both nine month periods ended September 30, 2007 and 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. We receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our condensed consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. These benefits were $1.0 and $1.5 million for the nine months ended September 30, 2007 and 2006, respectively. The benefit for 2007 has not been recognized in the financial statements as these benefits have not been realized since we are in a tax net operating loss position for the first nine months of 2007.

Net cash proceeds from the exercise of stock options were $1.9 million and $3.6 million for the nine months ended September 30, 2007 and 2006. The actual income tax benefit realized from stock option exercises was $1.2 million and $2.0 million for the same periods.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in “General and administrative, net” in the accompanying condensed consolidated statements of income, and was $2.5 million and $1.8 million for the quarters ended September 30, 2007 and 2006, respectively. Stock compensation expense for the nine months ended September 30, 2007 and 2006 was $7.4 million and $5.1 million, respectively. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

Stock Options

We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods:

	Three Months Ended September 30,		Nine months Ended September 30,	
	2007	2006	2007	2006
Dividend yield	0%	0%	0%	0%
Expected volatility	37.5%	39.1%	38.5%	39.5%
Risk-free interest rate	4.0%	4.8%	4.8%	4.9%
Expected life of options (in years)	4.3	2.6	6.2	5.6
Weighted-average grant-date fair value	$ 14.83	$ 12.20	$ 20.05	$ 19.31

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility, and based on an analysis of all relevant factors; use a three-year period to estimate expected volatility of our stock option grants.

At September 30, 2007, there was $3.8 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.3 years. The following table represents stock option activity for the nine months ended September 30, 2007:

	Shares	**Wtd. Avg. Exer. Price**
Options outstanding, beginning of period	1,549,140	$ 24.59
Options granted	193,057	$ 43.51
Options canceled	(15,591)	$ 35.02
Options exercised	(172,409)	$ 15.52
Options outstanding, end of period	1,554,197	$ 27.84
Options exercisable, end of period	836,679	$ 24.72

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at September 30, 2007 was $22.2 million and 5.4 years and $13.9 million and 4.0 years, respectively. Total intrinsic value of options exercised during the nine months ended September 30, 2007 was $4.6 million.

Restricted Stock

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to five years).

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2007, we had unrecognized compensation expense of approximately $18.9 million associated with these awards which are expected to be recognized over a weighted-average period of 1.8 years. The total fair value of shares vested during the first nine months ended September 30, 2007 was $7.9 million.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

The following table represents restricted stock activity for the nine months ended September 30, 2007:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	503,184	$ 40.04
Restricted shares granted	319,730	$ 43.15
Restricted shares canceled	(33,584)	$ 42.29
Restricted shares vested	(183,334)	$ 40.03
Restricted shares outstanding, end of period	605,996	$ 41.56

(4) Earnings Per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants to employees using the treasury stock method. Certain of our stock options, that could potentially dilute Basic EPS in the future, were anti-dilutive for periods ended September 30, 2007 and 2006, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the periods ended September 30, 2007 and 2006:

(in thousands, except per share data)	Three Months Ended September 30,					
	2007			2006		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 42,282	30,051	$ 1.41	$ 50,812	29,252	$ 1.74
Dilutive Securities:						
Restricted Stock	---	158		---	131	
Stock Options	---	477		---	801	
Diluted EPS:						
Net Income and Assumed Share Conversions	$ 42,282	30,686	$ 1.38	$ 50,812	30,184	$ 1.68

(in thousands, except per share data)	Nine Months Ended September 30,					
	2007			2006		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 101,380	29,937	$ 3.39	$ 126,295	29,161	$ 4.33

Dilutive Securities:										
Restricted Stock		---	161				---	125		
Stock Options		---	484				---	777		
Diluted EPS:										
Net Income and Assumed Share Conversions	$	101,380	30,582	$	3.32	$	126,295	30,063	$	4.20

Options to purchase approximately 1.6 million shares at an average exercise price of $27.84 were outstanding at September 30, 2007, while options to purchase 2.0 million shares at an average exercise price of $23.25 were outstanding at September 30, 2006. Approximately 1.1 million and 1.2 million options to purchase shares were not included in the computation of Diluted EPS for the three months ended September 30, 2007 and 2006, respectively, and 1.1 million and 1.2 million options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2007 and 2006, respectively, because these options were anti-dilutive, in that the sum of the option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods. Employee restricted stock grants of 448,366 shares and 359,695 shares were not included in the computation of Diluted EPS for the three months ended September 30, 2007 and 2006, respectively, and 444,906 shares and 366,072 shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2007 and 2006, respectively, because these restricted stock grants were anti-dilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under the treasury stock method was greater than the average closing market price for the common shares during that period.

(5) Long-Term Debt

Our long-term debt, including the current portion, as of September 30, 2007 and December 31, 2006, was as follows:

(in thousands)	September 30, 2007	December 31, 2006
Bank Borrowings	$ ---	$ 31,400
7-5/8% senior notes due 2011	150,000	150,000
9-3/8% senior subordinated notes due 2012	---	200,000
7-1/8% senior notes due 2017	250,000	---
Long-Term Debt	$ 400,000	$ 381,400

At September 30, 2007, the aggregate maturities on our long-term debt are $150.0 million for 2011 and $250.0 million for 2017.

Bank Borrowings

At September 30, 2007, we had no borrowings under our $500.0 million credit facility with a syndicate of ten banks that had a borrowing base of $350.0 million and expires in October 2011. The interest rate is either (a) the lead bank's prime rate (7.75% at September 30, 2007) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. In October 2006, we increased, renewed, and extended this credit facility, increasing the facility to $500.0 million from $400.0 million, increasing the commitment amount under the borrowing base to $250.0 million from $150.0 million, and extending its expiration to October 3, 2011 from October 1, 2008. In April 2007 we increased the borrowing base to $350.0 million; and effective November 2007, we further increased it to $400.0 million. In September 2007, we increased the commitment amount under the borrowing base to $350.0 million from $250.0 million.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. Under the terms of the credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The borrowing base amount is re-determined at least every six months and the next scheduled borrowing base review is in May 2008.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.4 million and $0.2 million for the three months ended September 30, 2007 and 2006, respectively, and $3.0 million and $0.6 million for the nine months ended September 30, 2007 and 2006, respectively. The amount of commitment fees included in interest expense, net was $0.2 million and $0.1 million for three month periods ended September 30, 2007 and 2006, respectively, and $0.4 million for both the nine month periods ended September 30, 2007 and 2006, respectively.

Senior Notes Due 2017

These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commencing on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. In addition, prior to June 1, 2010, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.125% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $4.5 million and $6.0 million for three and nine month periods ended September 30, 2007.

Senior Notes Due 2011

These notes consist of $150.0 million of 7-5/8% senior notes due 2011, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. In addition, prior to July 15, 2007, we could have redeemed up to 35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $3.0 million for each of the three month periods ended September 30, 2007 and 2006, and $9.0 million and $8.9 million for the nine month periods ended September 30, 2007 and 2006, respectively.

Senior Subordinated Notes Due 2012

These notes consisted of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 16, 2002 and were scheduled to mature on May 1, 2012. Interest on these notes was payable semiannually on May 1 and November 1. As of June 18, 2007, we redeemed all $200.0 million of these notes. In the second quarter of 2007, we recorded a charge of $12.8 million related to the redemption of these notes, which is recorded in "Debt retirement costs" on the accompanying condensed consolidated statement of income. The costs were comprised of approximately $9.4 million of premium paid to redeem the notes, and $3.4 million to write-off unamortized debt issuance costs.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $4.8 million for the three month period ended September 30, 2006, and $8.9 million and $14.4 million for the nine month periods ended September 30, 2007 and 2006, respectively.

We have capitalized interest on our unproved properties in the amount of $2.2 million for each of the three month periods ended September 30, 2007 and 2006, and $7.2 million and $6.6 million for the nine month periods ended September 30, 2007 and 2006, respectively.

(6) Foreign Activities

As of September 30, 2007, our gross capitalized oil and gas property costs in New Zealand totaled approximately $354.3 million. Approximately $339.0 million has been included in the "Proved properties" portion of our oil and gas properties, while $15.3 million is included as "Unproved properties." Our functional currency in New Zealand is the U.S. dollar. Net assets of our New Zealand operations total $255.3 million at September 30, 2007.

(7) Acquisitions and Dispositions

In October 2006, we acquired interests in five South Louisiana fields. The property interests are located in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. We paid approximately $167.9 million in cash for these interests. After taking into account internal acquisition costs of $4.0 million, our total cost was $171.9 million. We allocated $154.6 million of the acquisition price to "Proved Properties," $28.8 million to "Unproved Properties," and recorded a liability for $11.5 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward.

In December 2006, we acquired additional interests in our Lake Washington field. We paid approximately $20.0 million in cash for these interests. After taking into account internal acquisition costs of $0.4 million, our total cost was $20.4 million. We allocated $18.7 million of the acquisition price to "Proved Properties," $2.5 million to "Unproved Properties," and recorded a liability for $0.8 million to "Asset Retirement Obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from this acquisition have been included in our accompanying consolidated statements of income from the date of acquisition forward.

(8) Subsequent Events

In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP. The total price for these interests was approximately $249.5 million. The property interests are located in the Sun TSH field in La Salle County, the Briscoe Ranch field primarily in Dimmit County, and the Las Tiendas field in Webb County. We have recorded $24.5 million in "Other current assets" at September 30, 2007 related to the deposit for this acquisition.

(9) Condensed Consolidating Financial Information

In December 2005, we amended the indenture for our 9-3/8% Senior Subordinated Notes due 2012 and our 7-5/8% Senior Notes due 2011 to reflect our new holding company organizational structure (as discussed in Note 2). Pursuant to the amendment, both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) became co-obligors of these senior notes and senior subordinated debt. Prior to amendment, Swift Energy Company was the sole obligor. Due to the redemption of the 9-3/8% senior subordinated notes in June 2007, Swift Energy Company and Swift Energy Operating, LLC remain co-obligors only under the indenture for our 7-1/8% senior notes as of June 1, 2007. The co-obligations are full and unconditional and are joint and several. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and significant subsidiaries:

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

Condensed Consolidating Balance Sheets

(in thousands)	September 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
ASSETS					
Current assets	$ ---	$ 96,039	$ 22,857	$ ---	$ 118,896
Property and equipment	---	1,405,457	232,291	---	1,637,748
Investment in subsidiaries (equity method)	911,136	---	702,442	(1,613,578)	---
Other assets	---	39,642	758	(30,475)	9,925
Total assets	$ 911,136	$ 1,541,138	$ 958,348	$ (1,644,053)	$ 1,766,569
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 132,538	$ 6,247	$ ---	$ 138,785
Long-term liabilities	---	706,158	40,965	(30,475)	716,648
Stockholders' equity	911,136	702,442	911,136	(1,613,578)	911,136
Total liabilities and stockholders' equity	$ 911,136	$ 1,541,138	$ 958,348	$ (1,644,053)	$ 1,766,569

(in thousands)	December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
ASSETS					
Current assets	$ ---	$ 75,270	$ 17,303	$ ---	$ 92,573
Property and equipment	---	1,239,722	243,590	---	1,483,312
Investment in subsidiaries (equity method)	797,917	---	590,720	(1,388,637)	---
Other assets	---	42,519	705	(33,427)	9,797
Total assets	$ 797,917	$ 1,357,511	$ 852,318	$ (1,422,064)	$ 1,585,682

LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 137,016	$ 8,959	$ ---	$ 145,975
Long-term liabilities	---	629,775	45,442	(33,427)	641,789
Stockholders' equity	797,917	590,720	797,917	(1,388,637)	797,917
Total liabilities and stockholders' equity	$ 797,917	$ 1,357,511	$ 852,318	$ (1,422,064)	$ 1,585,682

Condensed Consolidating Statements of Income

(in thousands)	**Three Months Ended September 30, 2007**				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
Revenues	$ ---	$ 171,273	$ 9,947	$ ---	$ 181,220
Expenses	---	100,195	11,408	---	111,603
Income (loss) before the following:	---	71,078	(1,461)	---	69,617
Equity in net earnings of subsidiaries	42,282	---	42,915	(85,197)	---
Income before income taxes	42,282	71,078	41,454	(85,197)	69,617
Income tax provision (benefit)	---	28,163	(828)	---	27,335
Net income	$ 42,282	$ 42,915	$ 42,282	$ (85,197)	$ 42,282

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in thousands)	Nine Months Ended September 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
Revenues	$ ---	$ 457,658	$ 32,824	$ ---	$ 490,482
Expenses	---	296,105	33,186	---	329,291
Income (loss) before the following:	---	161,553	(362)	---	161,191
Equity in net earnings of subsidiaries	101,380	---	99,883	(201,263)	---
Income before income taxes	101,380	161,553	99,521	(201,263)	161,191
Income tax provision (benefit)	---	61,670	(1,859)	---	59,811
Net income	$ 101,380	$ 99,883	$ 101,380	$ (201,263)	$ 101,380

(in thousands)	Three Months Ended September 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
Revenues	$ ---	$ 153,279	$ 20,179	$ ---	$ 173,459
Expenses	---	77,409	13,841	---	91,250
Income (loss) before the following:	---	75,871	6,338	---	82,209
Equity in net earnings of subsidiaries	50,812	---	46,342	(97,154)	---
Income before income taxes	50,812	75,871	52,681	(97,154)	82,209
Income tax provision (benefit)	---	29,528	1,869	---	31,398
Net income	$ 50,812	$ 46,342	$ 50,812	$ (97,154)	$ 50,812

(in thousands)	Nine months Ended September 30, 2006				
	Swift Energy	**Swift Energy**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co.**

	Co. (Parent and Co-obligor)	Operating, LLC (Co-obligor)			Consolidated
Revenues	$ ---	$ 406,080	$ 50,725	$ ---	$ 456,805
Expenses	---	218,391	38,241	---	256,631
Income (loss) before the following:	---	187,690	12,484	---	200,174
Equity in net earnings of subsidiaries	126,295	---	116,811	(243,105)	---
Income before income taxes	126,295	187,690	129,295	(243,105)	200,174
Income tax provision (benefit)	---	70,879	3,000	---	73,879
Net income	$ 126,295	$ 116,811	$ 126,295	$ (243,105)	$ 126,295

Condensed Consolidating Statements of Cash Flows

(in thousands)	Nine Months Ended September 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
Cash flow from operations	$ ---	$ 322,220	$ 18,099	$ ---	$ 340,319
Cash flow from investing activities	---	(323,147)	(9,095)	(2,952)	(335,194)
Cash flow from financing activities	---	5,528	(2,952)	2,952	5,528
Net increase in cash	$ ---	$ 4,601	$ 6,052	$ ---	$ 10,653
Cash, beginning of period	---	50	1,008	---	1,058
Cash, end of period	$ ---	$ 4,651	$ 7,060	$ ---	$ 11,711

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in thousands)	Nine Months Ended September 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
Cash flow from operations	$ ---	$ 281,570	$ 29,113	$ ---	$ 310,683
Cash flow from investing activities	---	(237,602)	(46,844)	10,105	(274,342)
Cash flow from financing activities	---	5,772	10,105	(10,105)	5,772
Net increase in cash	$ ---	$ 49,740	$ (7,627)	$ ---	$ 42,113
Cash, beginning of period	---	44,911	8,094	---	53,005
Cash, end of period	$ ---	$ 94,651	$ 467	$ ---	$ 95,118

(10) Segment Information

Swift Energy has two reportable segments, one domestic and one foreign, both of which are in the business of oil and natural gas exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate our performance based on pre-tax profit or loss from oil and gas operations before price-risk management and other, net, general and administrative, net, debt retirement costs, and interest expense, net. Our reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

(in thousands)	Three Months Ended September 30,					
		2007			**2006**	
	Domestic	**New Zealand**	**Total**	**Domestic**	**New Zealand**	**Total**
Oil and gas sales	$ 170,001	$ 9,524	$ 179,525	$ 153,754	$ 19,615	$ 173,369
Costs and Expenses:						
Depreciation, depletion and amortization	48,431	5,137	53,568	37,619	8,249	45,868
Accretion of asset retirement obligation	341	47	388	134	38	172
Lease operating costs	17,896	3,634	21,530	9,620	3,306	12,926
Severance and other taxes	19,531	621	20,152	17,252	1,238	18,490
Income from oil and gas operations	$ 83,802	$ 85	$ 83,887	$ 89,129	$ 6,784	$ 95,913

Price-risk management and other, net	1,695	90
General and administrative, net	10,265	8,018
Interest expense, net	5,700	5,776
Income Before Income Taxes	$ 69,617	$ 82,209

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in thousands)	Nine Months Ended September 30,					
	2007			2006		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	$ 456,534	$ 31,694	$ 488,228	$ 403,129	$ 50,187	$ 453,316
Costs and Expenses:						
Depreciation, depletion and amortization	134,007	16,887	150,894	97,614	22,537	120,151
Accretion of asset retirement obligation	1,031	139	1,170	555	111	666
Lease operating costs	49,788	10,172	59,960	36,342	9,502	45,844
Severance and other taxes	53,372	2,093	55,465	45,958	3,253	49,211
Income from oil and gas operations	$ 218,336	$ 2,403	$ 220,739	$ 222,660	$ 14,784	$ 237,444
Price-risk management and other, net			2,254			3,489
General and administrative, net			29,295			23,323
Interest expense, net			19,742			17,436
Debt retirement cost			12,765			---
Income Before Income Taxes			$ 161,191			$ 200,174
Total Assets	$ 1,511,303	$ 255,266	$ 1,766,569	$ 1,170,096	$ 266,407	$ 1,436,503

MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RSULTS OF OPERATIONS
SWIFT ENERGY COMPANY AND SUBSIDIARIES

ITEM 2.

You should read the following discussion and analysis in conjunction with our financial information and our condensed consolidated financial statements and notes thereto included in this report and our Annual Report on Form 10-K for the year ended December 31, 2006. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 31 of this report.

Overview

Swift Energy's third quarter included both strong domestic production and increased crude oil and NGL prices. Given the current commodity price environment, our production weighting of 68% crude oil and NGLs continues to aid our overall price realizations. Including our October 2007 South Texas acquisition, we estimate full year 2007 production growth of 3% to 4% over 2006 levels. We had previously reduced this amount to 1% to 3% due to timing delays with projects and market constraints domestically, and production declines in New Zealand. Similarly, including the South Texas acquisition, we now estimate reserves growth will be between 7% and 12% for the year, without any adjustments for the strategic review outcome of our New Zealand assets. Facility, pressure maintenance and pipeline expansions scheduled for completion in 2008 will help alleviate the production constraints in our South Louisiana region.

During the second quarter of 2007, we began a review of strategic alternatives for our New Zealand operating unit, Swift Energy New Zealand, Ltd., often referred to as "SENZ." Such alternatives include an outright sale or merger of some or all of the properties and facilities, entry into joint ventures or reshaping of our long-term operational strategy there. We retained Scotia Waterous (USA) Inc. as an advisor to the potential sale of some or all of our New Zealand assets owned and operated by SENZ. The strategic review is expected to be completed by year end.

In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP. The total price for these interests was approximately $249.5 million. The property interests are located in the Sun TSH field in La Salle County, the Briscoe Ranch field primarily in Dimmit County, and the Las Tiendas field in Webb County. We plan to add more producing acreage in this area as well, and maintain a two rig drilling program in this area into 2008.

In the third quarter of 2007 as compared to the same period in 2006, our revenues increased 4% to $181.2 million but total costs increased 22% during the same period to $111.6 million, resulting in net income of $42.3 million, a 17% decrease. Our revenue increase is attributable to higher oil and NGL prices and higher domestic natural gas production, offset by decreased production in New Zealand. Our overall production decreased 3% to 18.2 Bcfe for the third quarter of 2007 as compared to third quarter 2006 production, including domestic production of 16.2 Bcfe, a 7% increase, and 1.9 Bcfe produced in New Zealand, a 45% decrease. For the nine months ended September 30, 2007, net income decreased 20% to $101.4 million, revenues increased 7% to $490.5 million, and production increased 3% to a record 53.4 Bcfe, all as compared to the same period in 2006. The oil and gas sector, including Swift Energy Company, continued to see third party vendor costs increase during the third quarter.

Cash flow provided by operating activities increased 6% to $134.3 million for the third quarter of 2007, again compared to the cash flow provided by operating activities in the third quarter of 2006.

To allow for further production increases in our South Louisiana region, construction continues on a new barge mounted production facility. This facility will add 10,000 barrels per day of oil processing capacity in Lake Washington, and will be completed in the first half of 2008. Planning for an expansion of pipeline capacity in Bay de Chene began during the second quarter of 2007. This expansion is also expected to be completed in 2008.

We will continue to utilize our proprietary merged 3D seismic data set in and around our asset base. This data set is allowing our high impact exploration inventory to grow in conjunction with an improving developmental drilling program. We currently have a total of 11 rigs operating, including five barge rigs in our South Louisiana region, with two in the Lake Washington area, one rig in both the Bay de Chene and Cote Blanche Island Fields, as well a non-operated rig in the Bayou Sale/Horseshoe Bayou area. We also have six land rigs currently operating, three rigs in the AWP Olmos area, two rigs operating in South Bearhead Creek, and one rig in the recently acquired Sun TSH area and a second rig is expected to return to this South Texas area in the near future. No drilling activity occurred in our New Zealand region during the first nine months of 2007 and due to the on-going strategic review, no new drilling activity is planned for the remainder of the year.

Results of Operations – Three Months Ended September 30, 2007 and 2006

Revenues. Our revenues in the third quarter of 2007 increased by 4% compared to revenues in the same period in 2006, due primarily to an increase in oil prices and higher domestic natural gas production, partially offset by decreased production in New Zealand. In the third quarter of 2007, oil production made up 61% of total production, natural gas made up 32%, and NGL represented 7%. In the third quarter of 2006, oil production made up 64% of total production, natural gas made up 29%, and NGL represented 7%.

Our third quarter 2007 weighted average prices increased 7% to $9.89 per Mcfe from $9.24 in the third quarter of 2006, with oil prices increasing 9% to $76.17 per barrel from $69.62, natural gas prices increasing 5% to $5.11 per Mcf from $4.87, and NGL prices rising 26% to $45.59 per barrel from $36.18.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the periods ended September 30, 2007 and 2006:

	Three Months Ended September 30,			
Regions	**Oil and Gas Sales (In Millions)**		**Net Oil and Gas Sales Volumes (Bcfe)**	
	2007	**2006**	**2007**	**2006**
South Texas	$ 12.7	$ 15.0	1.8	2.2
Toledo Bend	13.6	10.1	1.5	1.3
South Louisiana	142.4	127.9	12.8	11.6
Other	1.3	0.8	0.1	0.1
Total Domestic	$ 170.0	$ 153.8	16.2	15.2
New Zealand	9.5	19.6	1.9	3.5
Total	$ 179.5	$ 173.4	18.2	18.8

The following table provides additional information regarding our quarterly oil and gas sales:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
2007							
Three Months Ended September 30:							
Domestic	1,783	189	4.4	16.2	$ 76.20	$ 48.89	$ 5.68
New Zealand	48	41	1.4	1.9	$ 74.92	$ 30.17	$ 3.32
Total	1,831	230	5.8	18.2	$ 76.17	$ 45.59	$ 5.11
2006							
Three Months Ended September 30:							
Domestic	1,824	159	3.3	15.2	$ 69.54	$ 42.37	$ 6.07
New Zealand	168	61	2.2	3.5	$ 70.49	$ 20.09	$ 3.04
Total	1,992	220	5.5	18.8	$ 69.62	$ 36.18	$ 4.87

In the third quarter of 2007, our $6.2 million increase in oil, NGL, and natural gas sales resulted from:

- Volume variances that had a $9.3 million unfavorable impact on sales, with $11.2 million of decreases coming from the 161,000 Bbl decrease in oil sales volumes, partially offset by $0.4 million of increases attributable to the 10,000 Bbl increase in NGL sales volumes, and $1.5 million of increases due to the 0.3 Bcf increase in gas sales volumes; and
- Price variances that had a $15.5 million favorable impact on sales, with $12.0 million of increases attributable to the 9% increase in average oil prices received, $1.4 million of increases attributable to the 5% increase in average gas prices received, and $2.1 million of increases attributable to the 26% increase in average NGL prices received.

Costs and Expenses. Our expenses in the third quarter of 2007 increased $20.4 million, or 22%, compared to expenses in the same period of 2006. The increase was mainly due to a $7.7 million increase in DD&A as our production and the depletable oil and gas property base increased, an $8.6 million increase in lease operating expenses due to increased production and higher processing costs in the current quarter, and a reduction of cost in the third quarter of 2006 related to the settlement of insurance claims from hurricanes Katrina and Rita.

Our third quarter 2007 general and administrative expenses, net, increased $2.2 million, or 28%, from the level of such expenses in the same 2006 period. This increase was primarily due to costs associated with the New Zealand strategic evaluation project along with ongoing support costs of our new computer system implemented in 2007. For the third quarters of 2007 and 2006, our capitalized general and administrative costs, including capitalized stock compensation, totaled $7.6 million and $8.1 million, respectively. Our net general and administrative expenses per Mcfe produced were $0.57 per Mcfe in the third quarter 2007 and $0.43 per Mcfe in the third quarter of 2006. The portion of supervision fees recorded as a reduction to general and administrative expenses was $2.7 million for the third quarter of 2007 and $2.2 million for the 2006 period.

DD&A increased $7.7 million, or 17%, in the third quarter of 2007 from the level of those expenses in the same period of 2006. Domestically, DD&A increased $10.8 million in the third quarter of 2007 due to increases in the depletable oil and gas property base, including future development costs and higher production in the 2007 period. In New Zealand, DD&A decreased by $3.1 million in the third quarter of 2007 due to lower production during the 2007 period and due to decreases in the depletable oil and gas property base, partially offset by lower reserves volumes. Our DD&A rate per Mcfe of production was $2.95 and $2.45 in the third quarters of 2007 and 2006, respectively.

We recorded $0.4 million and $0.2 million of accretion to our asset retirement obligation in the third quarters of 2007 and 2006.

Our lease operating costs in the third quarter of 2007 increased $8.6 million, or 67%, over the level of such expenses in the same 2006 period. Domestically, lease operating costs increased $8.3 million due to higher production from our South Louisiana area, including costs from properties acquired in the fourth quarter of 2006, and a change in the recognition of natural gas and NGL processing costs in the 2007 period. The third quarter of 2006 was also impacted by a $2.8 million reduction in costs related to the settlement of insurance claims from hurricanes Katrina and Rita. Our lease operating costs in New Zealand increased by $0.3 million due to increases in plant and well operating costs. Our lease operating costs per Mcfe produced were $1.19 in the third quarter of 2007 and $0.69 in the third quarter of 2006.

In the third quarter of 2007, severance and other taxes increased $1.7 million, or 9%, over levels in the third quarter of 2006. The increase was due primarily to increased domestic production volumes and commodity pricing. Severance and other taxes, as a percentage of oil and gas sales, were approximately 11.2% and 10.7% in the third quarters of 2007 and 2006, respectively.

Our total interest cost in the third quarter of 2007 was $7.9 million, of which $2.2 million was capitalized. Our total interest cost in the third quarter of 2006 was $8.0 million, of which $2.2 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the third quarter of 2007 was primarily attributable to decreased interest costs on our notes as a result of our notes refinancing during the second quarter of 2007, partially offset by an increase in borrowings against our line of credit.

Our overall effective tax rate was 39.3% and 38.2% in the third quarters of 2007 and 2006. The increase from the third quarter of 2006 rate is primarily attributable to the $2.6 million increase in the valuation allowance of our capital loss carryforward asset which was recorded in the third quarter of 2007. Additionally, the effective income tax rate for both periods was higher than the U.S. statutory rate due to state income taxes, partially offset by reductions attributable to the currency effect on the New Zealand operations.

Net Income. For the third quarter of 2007, our net income of $42.3 million was 17% lower, and Basic EPS of $1.41 was 19% lower, than our third quarter of 2006 net income of $50.8 million and Basic EPS of $1.74. Our Diluted EPS in the third quarter of 2007 of $1.38 was 18% lower than our third quarter of 2006 Diluted EPS of $1.68. These lower amounts are due to an increase in costs that exceeded the increase in oil and gas revenues during the third quarter of 2007.

Results of Operations – Nine months Ended September 30, 2007 and 2006

Revenues. Our revenues in the first nine months of 2007 increased by 7% compared to revenues in the same period in 2006, due primarily to an increase in production from our South Louisiana region, which includes the properties acquired during the fourth quarter of 2006, partially offset by lower production in New Zealand. These gains were increased by higher NGL prices and higher New Zealand natural gas prices. In the first nine months of 2007, oil production made up 63% of total production, natural gas made up 30%, and NGL represented 7%. In the first nine months of 2006, oil production made up 61% of total production, natural gas made up 33%, and NGL represented 6%. The percentage of our total production from oil increased as production in the South Louisiana region, which is predominantly oil, increased over 2006 levels.

Our first nine months of 2007 weighted average prices increased 4% to $9.14 per Mcfe from $8.78 in the first nine months of 2006, with oil prices decreasing slightly to $66.89 per barrel from $66.92, natural gas prices increasing 9% to $5.48 per Mcf from $5.02, and NGL prices rising 26% to $41.29 per barrel from $32.69.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the nine months ended September 30, 2007 and 2006:

	Nine Months Ended September 30,			
Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (Bcfe)	
	2007	2006	2007	2006
South Texas	$ 39.5	$ 48.6	5.4	6.6
Toledo Bend	32.7	27.4	3.8	3.4
South Louisiana	380.7	323.7	37.4	30.6
Other	3.6	3.4	0.4	0.5
Total Domestic	$ 456.5	$ 403.1	47.0	41.1
New Zealand	31.7	50.2	6.4	10.5

Total	$	488.2	$	453.3	53.4	51.6

MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

The following table provides additional information regarding our oil & gas sales for the nine months ended September 30, 2007 and 2006:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	**NGL (MBbl)**	**Gas (Bcf)**	**Combined (Bcfe)**	**Oil (Bbl)**	**NGL (Bbl)**	**Gas (Mcf)**
2007							
Nine Months Ended September 30:							
Domestic	5,428	457	11.7	47.0	$ 66.76	$ 44.90	$ 6.32
New Zealand	172	136	4.6	6.5	$ 71.06	$ 29.16	$ 3.35
Total	5,600	593	16.3	53.4	$ 66.89	$ 41.29	$ 5.48
2006							
Nine Months Ended September 30:							
Domestic	4,866	319	10.0	41.1	$ 66.75	$ 41.29	$ 6.53
New Zealand	373	191	7.1	10.5	$ 69.13	$ 18.29	$ 2.92
Total	5,239	510	17.1	51.6	$ 66.92	$ 32.69	$ 5.02

In the first nine months of 2007, our $34.9 million increase in oil, NGL, and natural gas sales resulted from:

- Volume variances that had a $22.6 million favorable impact on sales, with $24.2 million of increases coming from the 361,000 Bbl increase in oil sales volumes, and $2.7 million of increases attributable to the 83,000 Bbl increase in NGL sales volumes, partially offset by $4.3 million of decreases due to the 0.9 Bcf decrease in gas sales volumes; and

- Price variances that had a $12.3 million favorable impact on sales, of which $7.4 million of increases attributable to the 9% increase in average gas prices received, and by $5.1 million of increases attributable to the 26% increase in average NGL prices received, offset slightly by $0.2 million of decreases attributable to the less than 1% decrease in average oil prices received.

Costs and Expenses. Our expenses in the first nine months of 2007 increased $72.7 million, or 28%, compared to expenses in the same period of 2006. The increase was mainly due to a $30.7 million increase in DD&A as our production and depletable oil and gas property base increased, a $14.1 million increase in lease operating expenses due to higher production and processing costs, $12.8 million of debt retirement costs related to the redemption of our 9-3/8% Notes due 2012, and a $6.3 million increase in severance and other taxes due to increased domestic production volumes in the first nine months of 2007.

Our first nine months of 2007 general and administrative expenses, net, increased $6.0 million, or 26%, from the level of such expenses in the same 2006 period. This increase was primarily due to an expansion of our workforce and an increase in stock compensation expense, along with costs associated with the New Zealand strategic evaluation project and ongoing support costs of our new computer system implemented in 2007. For the first nine months of 2007 and 2006, our capitalized general and administrative costs, including capitalized stock compensation, totaled $23.0 million and $20.7 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to the geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced were $0.55 per Mcfe in the first nine months of 2007 and $0.45 per Mcfe in the first nine months of 2006. The portion of supervision fees recorded as a reduction to general and administrative expenses was $8.0 million for the first nine months of 2007 and $6.4 million for the 2006 period.

DD&A increased $30.7 million, or 26%, in the first nine months of 2007 from the level of those expenses in the same period of 2006. Domestically, DD&A increased $36.4 million in the first nine months of 2007 due to increases in the depletable oil and gas property base, including future development costs and higher production in the 2007 period. In New Zealand, DD&A decreased by $5.7 million in the first nine months of 2007 due to lower production and decreases in the depletable oil and gas property base, partially offset by lower reserves volumes. Our DD&A rate per Mcfe of production was $2.82 and $2.33 in the first nine months of 2007 and 2006, respectively.

We recorded $1.2 million and $0.7 million of accretions to our asset retirement obligation in the first nine months of 2007 and 2006.

Our lease operating costs in the first nine months of 2007 increased $14.1 million, or 31%, over the level of such expenses in the same 2006 period. Domestically, lease operating costs increased $13 due to higher production from our South Louisiana area, including costs from properties acquired in the fourth quarter of 2006, and a change in the recognition of natural gas and NGLprocessing costs in the 2007 period; while 2006 amounts included a $2.8 million reduction in costs related to the settlement of insurance claims from hurricanes Katrina and Rita. Our lease operating costs in New Zealand increased by $0.7 million due to increases in plant and well operating costs. Our lease operating costs per Mcfe produced were $1.12 in the first nine months of 2007 and $0.89 in the first nine months of 2006.

In the first nine months of 2007, severance and other taxes increased $6.3 million, or 13%, over levels in the first nine months of 2006. The increase was due primarily to higher production in South Louisiana. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance taxes to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 11.4% and 10.9% in the first nine months of 2007 and 2006, respectively.

Our total interest cost in the first nine months of 2007 was $26.9 million, of which $7.2 million was capitalized. Our total interest cost in the first nine months of 2006 was $24.0 million, of which $6.6 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the first nine months of 2007 was primarily attributable to increased borrowings against our line of credit and was also impacted by our note refinancing as we recorded, in June 2007, a partial month of interest on our retired $200 million notes and a full month of interest on our new $250 million notes. These increased costs were offset partially by higher capitalized costs and lower interest expense on our new $250 million notes during the third quarter of 2007. The increase in borrowings during the first nine months of 2007 was primarily due to our fourth quarter 2006 property acquisitions.

In the second quarter of 2007, we incurred $12.8 million of debt retirement costs related to the redemption of our 9-3/8% senior notes due 2012. The costs were comprised of approximately $9.4 million of premiums paid to repurchase the notes, and $3.4 million to write-off unamortized debt issuance costs.

Our overall effective tax rate was 37.1% and 36.9% in the first nine months of 2007 and 2006, respectively. The effective income tax rate for both periods was higher than the U.S. statutory rate primarily due to state income taxes, and was partially offset by reductions attributable to the currency effect on the New Zealand operations. The nine month period of 2007 was also impacted by a $2.6M increase in the valuation allowance of our capital loss carryforward asset, offset somewhat by a decrease in the New Zealand statutory tax rate.

Net Income. For the first nine months of 2007, our net income of $101.4 million was 20% lower, and Basic EPS of $3.39 was 22% lower, than our first nine months of 2006 net income of $126.3 million and Basic EPS of $4.33. Our Diluted EPS in the first nine months of 2007 of $3.32 was 21% lower than our first nine months of 2006 Diluted EPS of $4.20. These lower amounts are due to an increase in costs that exceeded the increase in oil and gas revenues during the first nine months of 2007 and were also impacted by the $12.8 million in expenses related to our notes refinancing during the second quarter of 2007.

Share-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R, "Share-Based Payment" utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with APB No. 25, "Accounting for Stock Issued to Employees" (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants. The adoption of SFAS No. 123R increased our compensation expense related to employee stock option grants over pre-implementation period levels.

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized in both the three months ended September 30, 2007 and 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying condensed consolidated statements of operations.

We continue to use the Black-Scholes-Merton option pricing model to estimate the fair value of stock-option awards with the following weighted-average assumptions for the indicated periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Dividend yield	0%	0%	0%	0%
Expected volatility	37.5%	39.1%	38.5%	39.5%
Risk-free interest rate	4.0%	4.8%	4.8%	4.9%
Expected life of options (in years)	4.3	2.6	6.2	5.6
Weighted-average grant-date fair value	$ 14.83	$ 12.20	$ 20.05	$ 19.31

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility and based on analysis of all relevant factors use a three-year period to estimate expected volatility of our stock option grants. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

At September 30, 2007, there was $3.8 million of unrecognized compensation cost related to stock options, which are expected to be recognized over a weighted-average period of 1.3 years, and unrecognized compensation expense of $18.9 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 1.8 years. The compensation expense for restricted stock awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2006 amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis" in our Annual Report on form 10-K for the period ending December 31, 2006.

Internal Control over Financial Reporting

We began an implementation of a new computer system in early 2006; and effective April 1, 2007, we went operational with core elements of the new system. When fully functional, this system will fully integrate our accounting processes from production of oil and gas to receipt of cash and from procurement of products and services to payment for such costs. It also further automates our financial reporting processes. The system being replaced utilizes multiple systems that covered the production of oil and gas, procurement of products and services, and the financial reporting process. With this new computer system, we anticipate a positive impact on our internal control over financial reporting, and the Company has updated its internal control over financial reporting as necessary to accommodate these changes.

With this change, management testing of the effectiveness of the new system's impact on the Company's internal control environment is ongoing, and most likely will not be complete until late 2007. Until the system is fully tested, management continues to perform other parallel procedures and analyses related to the financial closing and accrual processes to ensure the integrity of our financial statements.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased in 2007 from levels seen in late 2006 and it is currently significantly higher when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the Middle East and Africa, can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain higher when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, availability of LNG from foreign sources, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Income Tax Regulations

The tax laws in the jurisdictions in which we operate continuously change and professional judgments regarding such tax laws can differ.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to our deferred tax liability. This is also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We do not expect to recognize significant increases or decreases in unrecognized tax benefits during the year ended December 31, 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2006 and September 30, 2007 no interest or penalties relating to income taxes have been recognized.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward remain subject to examination by tax authorities. Our Texas franchise tax returns for 2005 and prior years have been audited by the Texas State Comptroller. There are no unresolved items related to those audits. No other state returns are significant to our financial position. Our New Zealand income tax returns from 2002 forward remain subject to examination by the local tax authority.

In the third quarter of 2007 we increased the valuation allowance for our capital loss carryforward assets by $2.6 million. The increase in the valuation allowance is due to changes in our property disposition plans and increased income tax expense by $2.6 million in that period.

Liquidity and Capital Resources

During the first nine months of 2007, we relied upon our net cash provided by operating activities of $340.3 million to fund capital expenditures of $335.9 million. During the first nine months of 2006, we relied upon our net cash provided by operating activities of $310.7 million and proceeds from the sale of property and equipment of $20.3 million to fund capital expenditures of $295.5 million.

Subsequent Events. In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP. The total price for these interests was approximately $249.5 million. The property interests are located in the Sun TSH field in La Salle County, the Briscoe Ranch field primarily in Dimmit County, and the Las Tiendas field in Webb County. We have recorded $24.5 million in "Other current assets" at September 30, 2007 related to the deposit for this acquisition.

Acquisitions. In October 2006, we acquired interests in five South Louisiana fields from BP America Production Company. The total price for these interests was approximately $168 million. The property interests are located primarily in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. In addition, we have acquired virtually all of the remaining outstanding interest in the South Bearhead Creek field, located in Beauregard Parish, Louisiana, for $4.5 million in November 2006.

Net Cash Provided by Operating Activities. For the first nine months of 2007, our net cash provided by operating activities was $340.3 million, representing a 10% increase as compared to $310.7 million generated during the same 2006 period. The $29.6 million increase in the first nine months of 2007 was primarily due to adding back increased DD&A and debt retirement costs, and an increase in accounts receivable in the 2006 period, somewhat offset by a lower net income and deferred income taxes for the nine months ended at September 30, 2007.

Accounts Receivable. We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both September 30, 2007 and December 31, 2006, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Existing Bank Credit Facility. We had no borrowings at September 30, 2007 and $31.4 million in borrowings under our bank credit facility at December 31, 2006. On June 1, 2007, the facility was paid down with proceeds from the issuance of $250.0 million in senior notes issued on that date as described below along with cash flow from operating activities during that period. Effective November 2007, our bank credit facility consists of a $500.0 million revolving line of credit with a $400.0 million borrowing base. The borrowing base is re-determined at least every six months and the next scheduled review is in May 2008. Under the terms of our bank credit facility, we can increase the commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. In September 2007, we increased the commitment amount from $250.0 million to $350.0 million. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Our access to funds from our credit facility is not restricted under any “material adverse condition” clause, a clause that is common for credit agreements to include. A “material adverse condition” clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on our operations, financial condition, prospects or properties, and would impair our ability to make timely debt repayments. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

Repurchase of Senior Subordinated Notes due 2012. On June 18, 2007, we redeemed all $200.0 million of our senior subordinated notes due 2012, and recorded debt retirement costs of $12.8 million related to this redemption.

Issuance of Senior Notes due 2017. These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method.

Debt Maturities. Our credit facility, which did not have a balance at September 30, 2007, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $250.0 million of 7-1/8% senior notes mature June 1, 2017.

Working Capital. Our working capital improved from a deficit of $53.4 million at December 31, 2006, to a deficit of $19.9 million at September 30, 2007. The improvement was primarily due to our 2007 cash provided by operating activities exceeding our cash used in investing activities along with the issuance of our Notes due 2017 offset by the repurchase of our Notes due 2012 in June 2007.

Capital Expenditures. In the first nine months of 2007, we relied upon our net cash provided by operating activities of $340.3 million to fund capital expenditures of $335.9 million. Our total capital expenditures of approximately $335.9 million in the first nine months of 2007 included Domestic expenditures of $326.8 million and expenditures in New Zealand of $9.1 million.

We completed 35 of 42 domestic wells in the first nine months of 2007, for a success rate of 83%. A total of 21 wells were drilled in the Lake Washington area, of which 17 were completed, and seven wells were drilled and completed in the South Bearhead Creek area. Eight wells were also drilled and completed in the AWP Olmos area, and three out of six wells were drilled and completed in the Bay de Chene area. No drilling activity occurred in our New Zealand region during the first nine months of 2007 and due to the previously announced review of strategic alternatives in New Zealand, no drilling activity is planned there for the remainder of the year.

We adjusted our 2007 capital spending budget to a new range of $681 - $710 million, which now includes approximately $250 million for our October 2007 acquisition of South Texas properties, from the previous range of $375 - $400 million, which did not include acquisitions. Approximately 99% of the budget, excluding acquisitions, is targeted for domestic activities, predominantly in our South Louisiana region, with about 1% planned for maintenance activities in the New Zealand region. With our October 2007 South Texas acquisitions, we estimate full year production growth of 3% to 4% over 2006 levels, which includes domestic production growth of 13% to 14% over 2006 levels. Similarly, including the South Texas acquisition, we now believe reserves growth will be between 7% and 12% for the year, making no adjustments for the strategic review outcome of our New Zealand assets. We believe that capital expenditures will exceed our cash flow from operating activities, and we plan to fund these expenditures with our credit facility.

For the first nine months of 2007, we spent $335.9 million on capital expenditures compared to $295.5 for the 2006 period. For the last three months of 2007, we expect to make capital expenditures of approximately $345 to $375 million, including the October 2007 acquisition of South Texas properties. Capital expenditures for all of 2006 were $557.5 million.

During the last three months of 2007, we anticipate drilling or participation in the drilling of up to an additional nine wells in the South Louisiana region, an additional 20 wells, including properties purchased from Escondido Resources, LP, in the South Texas area, and up to four additional wells in the Toledo Bend region.

Our 2007 capital expenditures continue to be focused on developing and producing long-lived reserves in South Louisiana, South Texas, and Toledo Bend regions, along with property acquisitions and an expansion of our Lake Washington facilities. We expect our 2007 total production to increase over 2006 levels, primarily from our South Louisiana area, Toledo Bend area, and South Texas acquisitions. We expect production in our New Zealand region to decrease as a limited amount of new drilling is currently budgeted to offset the natural production decline of these regions.

New Accounting Pronouncements

Effective January 1, 2007, the Company adopted FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109" ("FIN 48"). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." See additional discussion of FIN 48 in the Income Taxes section of the footnotes. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to our deferred tax liability.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its financial position or results of operations.

Forward Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters and competition. Such forward-looking statements generally are accompanied by words such as "plan," "future," "estimate," "expect," "budget," "predict," "anticipate," "projected," "should," "believe" or other words that convey the uncertainty of events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and therefore, actual results may differ materially. Among the factors that could cause actual results to differ materially are the uncertainty of finding, replacing, developing or acquiring reserves; fluctuations in crude oil, natural gas and natural gas liquids prices or demand; adequate availability of markets, facilities, skilled personnel, services and supplies; hurricanes or tropical storms affecting operations; the uncertainty of drilling results; potential failure or delays in achieving reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance; requirements for capital; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed herein, and set forth from time to time in our other public reports, filings and public statements. Also, because of the volatility in oil and gas prices and other factors, interim results are not necessarily indicative of those for a full year.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Commodity Risk

Our major market risk exposure is the volatile 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. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of derivative instruments (such as futures, forward contracts, swaps, and option contracts such as floors and collars) to mitigate price risk associated with fluctuations in oil and natural gas prices. Below is a description of the derivative instruments we have utilized to hedge our exposure to price risk.

- Price Floors, Collars, and Swaps – At September 30, 2007, we did not have any price floors, collars, or swaps in place.

- New Zealand Gas Contracts – All of our current gas production in New Zealand is sold under fixed-price contracts denominated in New Zealand dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

Customer Credit Risk

We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe that the loss of any single oil or gas customer would have a material adverse effect on our financial position or results of operations.

Foreign Currency Risk

We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand dollar. Fluctuations in rates between the New Zealand dollar and U.S. dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax obligations, all denominated in New Zealand dollars. We use the U.S. dollar as our functional currency in New Zealand and because of this; our results of operations, cash flows and effective tax rate are impacted from fluctuations between the U.S. dollar and the New Zealand dollar.

Interest Rate Risk

Our Senior Notes due 2011 and Senior Notes due 2017 have fixed interest rates; consequently we are not exposed to cash flow risk from market interest rate changes on these notes. However, there is a risk that market rates will decline and the required interest payments on our Senior Notes and Senior Subordinated Notes may exceed those payments based on the current market rate. At September 30, 2007, we had no borrowings under our credit facility, which is subject to floating rates and therefore susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 78 basis points and would not have a material adverse effect on our 2007 cash flows based on this same level or a modest level of borrowing.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this report and have concluded that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the third quarter of 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

SWIFT ENERGY COMPANY

PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

No material legal proceedings are pending other than ordinary, routine litigation incidental to the Company's business.

Item 1A. Risk Factors.

There have been no material changes in our risk factors from those disclosed in our 2006 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The following table summarizes repurchases of our common stock occurring during the third quarter of 2007:

Period	Total Number of Shares Purchased	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 (in thousands)
07/01/07 – 07/31/07 (1)	15,384	$42.47	---	$---
08/01/07 – 08/31/07 (1)	3,788	41.77	---	---
09/01/07 – 09/30/07 (1)	---	---	---	---
Total	19,172	$42.33	---	$---

(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.

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.

1.1	Underwriting Agreement dated May 17, 2007 among Swift Energy Company, Swift Energy Operating, LLC and J.P. Morgan Securities Inc. (incorporated by reference as Exhibit 99.1 to Swift Energy Company's Form 8-K filed May 30, 2007, File No. 1-08754).
10.1*	Asset Purchase and Sale Agreement between Escondido Resources LP and Swift Energy Operating, LLC dated as of September 4, 2007 but effective as of July 1, 2007.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of 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.

SWIFT ENERGY COMPANY
(Registrant)

Date: November 1, 2007	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: November 1, 2007	By:	/s/ David W. Wesson. David W. Wesson Controller and Principal Accounting Officer