SWIFT ENERGY CO
Form 10-Q
August 08, 2008

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 June 30, 2008
Commission File Number 1-8754

SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

Texas (State of Incorporation)	20-3940661 (I.R.S. Employer Identification No.)

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Exchanges on Which Registered:
Common Stock, par value $.01 per share	New York Stock Exchange

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 þ Accelerated o Non-accelerated o

accelerated filer filer
filer

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

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

Common Stock	30,847,315 Shares
($.01 Par Value)	(Outstanding at July 31,
(Class of Stock)	2008)

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2008
INDEX

Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	June 30, 2008 (Unaudited)	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 13,147	$ 5,623
Accounts receivable-		
Oil and gas sales	99,887	72,916
Joint interest owners	1,346	1,587
Other Receivables	3,765	1,324
Deferred tax asset	7,788	8,055
Other current assets	20,310	13,896
Current assets held for sale	564	96,549
Total Current Assets	146,807	199,950
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	2,907,592	2,610,469
Unproved properties	108,290	106,643
	3,015,882	2,717,112
Furniture, fixtures, and other equipment	35,169	33,064
	3,051,051	2,750,176
Less – Accumulated depreciation, depletion, and amortization	(1,100,632)	(989,981)
	1,950,419	1,760,195
Other Assets:		
Debt issuance costs	6,688	7,252
Restricted assets	1,828	1,654
	8,516	8,906
	$ 2,105,742	$ 1,969,051
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 91,130	$ 89,281
Accrued capital costs	86,291	94,947
Accrued interest	7,198	7,558
Undistributed oil and gas revenues	3,852	10,309
Current liabilities associated with assets held for sale	---	8,066
Total Current Liabilities	188,471	210,161
Long-Term Debt	524,200	587,000
Deferred Income Taxes	373,438	302,303
Asset Retirement Obligation	34,607	31,066
Other Long-Term Liabilities	2,347	2,467
Commitments and Contingencies		

Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, $.01 par value, 85,000,000 shares authorized, 31,171,772 and 30,615,010 shares issued, and 30,740,616 and 30,178,596 shares outstanding, respectively	312	306
Additional paid-in capital	426,142	407,464
Treasury stock held, at cost, 431,156 and 436,414 shares, respectively	(8,196)	(7,480)
Retained earnings	566,458	436,178
Accumulated other comprehensive loss, net of income tax	(2,037)	(414)
	982,679	836,054
	$ 2,105,742	$ 1,969,051

See accompanying Notes to Consolidated Financial Statements.

3

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

	Three Months Ended		Six Months Ended	
	06/30/08	06/30/07	06/30/08	06/30/07
Revenues:				
Oil and gas sales	$ 263,184	$ 156,311	$ 463,157	$ 286,533
Price-risk management and other, net	(503)	99	(1,516)	(44)
	262,681	156,410	461,641	286,489
Costs and Expenses:				
General and administrative, net	10,291	9,620	20,210	17,209
Depreciation, depletion, and amortization	57,280	43,854	109,774	85,576
Accretion of asset retirement obligation	467	349	921	690
Lease operating cost	28,584	16,178	55,009	31,892
Severance and other taxes	26,856	17,791	48,992	33,841
Interest expense, net	8,231	7,296	16,921	14,042
Debt retirement cost	---	12,765	---	12,765
	131,709	107,853	251,827	196,015
Income from Continuing Operations Before Income Taxes	130,972	48,557	209,814	90,474
Provision for Income Taxes	47,727	18,034	76,734	33,506
Income from Continuing Operations	83,245	30,523	133,080	56,968
Income (Loss) from Discontinued Operations, net of taxes	(1,326)	987	(2,800)	2,130
Net Income	$ 81,919	$ 31,510	$ 130,280	$ 59,098
Per Share Amounts-				
Basic: Income from Continuing Operations	$ 2.72	$ 1.02	$ 4.37	$ 1.91
Income (Loss) from Discontinued Operations, net of taxes	(0.04)	0.03	(0.09)	0.07
Net Income	$ 2.68	$ 1.05	$ 4.27	$ 1.98
Diluted: Income from Continuing Operations	$ 2.66	$ 1.00	$ 4.27	$ 1.86
Income (Loss) from Discontinued Operations, net of taxes	(0.04)	0.03	(0.09)	0.07
Net Income	$ 2.61	$ 1.03	$ 4.18	$ 1.93
Weighted Average Shares Outstanding	30,608	29,930	30,478	29,880

See accompanying Notes to Consolidated Financial Statements.

4

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	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2006	$ 302	$ 387,556	$ (6,125)	$ 415,868	$ 316	$ 797,917
Stock issued for benefit plans (32,817 shares)	-	953	471	-	-	1,424
Stock options exercised (239,650 shares)	2	3,168	-	-	-	3,170
Purchase of treasury shares (42,145 shares)	-	-	(1,826)	-	-	(1,826)
Adoption of FIN 48	-	-	-	(977)	-	(977)
Excess tax benefits from stock-based awards	-	613	-	-	-	613
Employee stock purchase plan (17,678 shares)	-	619	-	-	-	619
Issuance of restricted stock (187,678 shares)	2	(2)	-	-	-	-
Amortization of stock compensation	-	14,557	-	-	-	14,557
Comprehensive income:						
Net income	-	-	-	21,287	-	21,287
Other comprehensive loss	-	-	-	-	(730)	(730)
Total comprehensive income						20,557
Balance, December 31, 2007	$ 306	$ 407,464	$ (7,480)	$ 436,178	$ (414)	$ 836,054
Stock issued for benefit plans (39,152 shares) (2)	-	1,018	671	-	-	1,689
Stock options exercised (376,966 shares) (2)	4	7,386	-	-	-	7,390
Purchase of treasury shares (33,894 shares) (2)	-	-	(1,387)	-	-	(1,387)
Excess tax benefits from stock-based awards (2)	-	1,083	-	-	-	1,083
Employee stock purchase plan (25,645 shares) (2)	-	944	-	-	-	944
Issuance of restricted stock (154,151 shares) (2)	2	(2)	-	-	-	-
Amortization of stock compensation (2)	-	8,249	-	-	-	8,249
Comprehensive income:						
Net income (2)	-	-	-	130,280	-	130,280
Other comprehensive loss (2)	-	-	-	-	(1,623)	(1,623)
						128,657

Total comprehensive income (2)												
Balance, June 30, 2008 (2)	$	312	$	426,142	$	(8,196)	$	566,458	$	(2,037)	$	982,679

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

See accompanying Notes to Consolidated Financial Statements.

5

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

(in thousands)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Cash Flows from Operating Activities:		
Net income	$ 130,280	$ 59,098
Plus (income) loss from discontinued operations, net of taxes	2,800	(2,130)
Adjustments to reconcile net income to net cash provided by operation activities -		
Depreciation, depletion, and amortization	109,774	85,576
Accretion of asset retirement obligation	921	690
Deferred income taxes	73,730	33,473
Stock-based compensation expense	5,965	5,147
Debt retirement costs – cash and non-cash	---	12,765
Other	(2,833)	(2,596)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	(31,948)	5,762
Increase (decrease) in accounts payable and accrued liabilities	6,493	(1,531)
Decrease in income taxes payable	(79)	(974)
Decrease in accrued interest	(360)	(1,897)
Cash Provided by operating activities – continuing operations	294,743	193,383
Cash Provided by operating activities – discontinued operations	6,690	12,672
Net Cash Provided by Operating Activities	301,433	206,055
Cash Flows from Investing Activities:		
Additions to property and equipment	(318,962)	(199,373)
Proceeds from the sale of property and equipment	113	215
Net cash received as operator of partnerships and joint ventures	---	485
Cash Used in investing activities – continuing operations	(318,849)	(198,673)
Cash Provided by (Used in) investing activities – discontinued operations	80,731	(7,536)
Net Cash Used in Investing Activities	(238,118)	(206,209)
Cash Flows from Financing Activities:		
Proceeds from long-term debt	---	250,000
Payments of long-term debt	---	(200,000)
Net payments from bank borrowings	(62,800)	(31,400)
Net proceeds from issuances of common stock	7,313	2,244
Excess tax benefits from stock-based awards	1,083	---
Purchase of treasury shares	(1,387)	(955)
Payments of debt retirement costs	---	(9,376)
Payments of debt issuance costs	---	(4,201)
Cash Provided by (Used in) financing activities – continuing operations	(55,791)	6,312
Cash Provided by financing activities – discontinued operations	---	---
Net Cash Provided by (Used in) financing activities	(55,791)	6,312
Net Increase in Cash and Cash Equivalents	$ 7,524	$ 6,158

Cash and Cash Equivalents at Beginning of Period	5,623	1,058
Cash and Cash Equivalents at End of Period	$ 13,147	$ 7,216
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$ 16,721	$ 15,275
Cash paid during period for income taxes	$ 3,005	$ 1,007

See accompanying Notes to 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, 2007 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying condensed consolidated financial statements include the accounts of Swift Energy Company ("Swift Energy") 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. Our undivided interests in gas processing plants are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying condensed consolidated financial statements.

Discontinued Operations. Certain amounts have been reclassified to present the Company's New Zealand operations as discontinued operations. Unless otherwise indicated, information presented in the notes to the condensed consolidated financial statements relates only to Swift's continuing operations. Information related to discontinued operations is included in Note 6 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

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 and assumptions 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 natural 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.

7

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.

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural 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 natural 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 six months ended June 30, 2008 and 2007, such internal costs capitalized totaled $14.7 million and $13.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the six months ended June 30, 2008 and 2007, capitalized interest on unproved properties totaled $3.9 million and $5.0 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural 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 natural gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization (“DD&A”) of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and natural gas properties—including future development costs, 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 natural gas produced during the period by the total estimated units of proved oil and natural 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, recorded 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 property-by-property 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, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural 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”). Our hedges at June 30, 2008 consisted of oil and natural gas price floors with strike prices lower than the period-end price and did not materially affect this calculation. This calculation is done 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 natural gas that are ultimately recovered.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly 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 natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, a non-cash write-down of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a sizable decrease in oil and/or natural gas prices were to occur.

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. 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 condensed consolidated balance sheets. 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 June 30, 2008, 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 collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At June 30, 2008 and December 31, 2007, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balances on the accompanying condensed consolidated balance sheets.

Price-Risk Management Activities. The Company 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 natural gas prices, mainly through the purchase of price floors and collars. During the second quarters of 2008 and 2007, we recognized net losses of $0.9 million and $0.4 million, respectively, relating to our derivative activities. During the first six months of 2008 and 2007, we recognized net losses of $1.9 million and $0.7 million, respectively, relating to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of income. Had these gains and losses been recognized in the oil and gas sales account they would not materially change our per unit sales prices received. At June 30, 2008, the Company had recorded $2.0 million, net of taxes of $1.2 million, of derivative losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying condensed consolidated balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in “Price-risk management and other, net” for the first six months of 2008 and 2007 was not material. All amounts currently held in “Accumulated other comprehensive loss, net of income tax” will be realized within the next six months when the forecasted sale of hedged production occurs.

At June 30, 2008, we had in place oil and natural gas price floors in effect for the contract months of July 2008 through December 2008 that cover a portion of our oil and natural gas production for July 2008 to December 2008. The oil price floors cover notional volumes of 1,530,000 barrels, with a weighted average floor price of $96.20 per barrel. Our oil price floors in place at June 30, 2008 are expected to cover approximately 49% to 54% of our estimated oil production from July 2008 to December 2008. The natural gas price floors cover notional volumes of 6,450,000 MMBtu, with a weighted average floor price of $9.23 per MMBtu. Our natural gas price floors in place at June 30, 2008 are expected to cover approximately 48% to 53% of our estimated natural gas production from July 2008 to December 2008.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and 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 loss, net of income tax.” When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from “Accumulated other comprehensive loss, net of income tax” and recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of income. The fair value of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at June 30, 2008, was $1.1 million and is recognized on the accompanying condensed consolidated balance sheet in “Other current assets.”

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.” Our supervision fees are based on COPAS determined rates. The amount of supervision fees charged in the first six months of 2008 and 2007 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $7.8 million and $5.2 million in the first six months of 2008 and 2007, respectively.

Inventories. We value inventories at the lower of cost or market value. Inventory is accounted for using the first in, first out method (“FIFO”). Inventories consisting of materials, supplies, and tubulars are included in “Other current assets” on the accompanying condensed consolidated balance sheets totaling $8.3 million at June 30, 2008 and $4.2 million at December 31, 2007.

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 other long-term liabilities. This was also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We did not recognize significant increases or decreases in unrecognized tax benefits during the quarters ended June 30, 2008 and 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of June 30, 2008 no interest or penalties relating to income taxes have been incurred or recognized. Our cumulative interest exposure on unrecognized tax benefits is not material.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2002, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

Accounts Payable and Accrued Liabilities. Included in “Accounts payable and accrued liabilities,” on the accompanying condensed consolidated balance sheets, at June 30, 2008 and December 31, 2007 are liabilities of approximately $17.0 million and $12.6 million, respectively, which represent the amounts by which checks issued, but not presented by vendors to the Company’s banks for collection, exceeded balances in the applicable disbursement bank accounts.

Accumulated Other Comprehensive Loss, 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 the Company. At June 30, 2008, we recorded $2.0 million, net of taxes of less than $1.2 million, of derivative losses in “Accumulated other comprehensive loss, net of income tax” on the accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2008 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2007	$ (658)	$ 244	$ (414)
Change in fair value of cash flow hedges	(4,268)	1,570	(2,698)
Effect of cash flow hedges settled during the period	1,702	(627)	1,075
Other comprehensive loss at June 30, 2008	$ (3,224)	$ 1,187	$ (2,037)

Total comprehensive income was $80.3 million and $31.9 million for the second quarters of 2008 and 2007, respectively. Total comprehensive income was $128.7 million and $59.0 million for the six months of 2008 and 2007, respectively.

Asset Retirement Obligation. We record these obligations in accordance with SFAS No. 143, “Accounting for Asset Retirement Obligations.” This 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 well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the estimated oil and natural gas reserves 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 balance. 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.

The following provides a roll-forward of our asset retirement obligation:

(in thousands)		2008		2007
Asset Retirement Obligation recorded as of January 1	$	34,459	$	28,794
Accretion expense for the six months ended June 30		921		690
Liabilities incurred for new wells and facilities construction		1,169		251
Reductions due to sold, or plugged and abandoned wells		(24)		---
Revisions in estimated cash flows		824		---
Asset Retirement Obligation as of June 30	$	37,349	$	29,735

At June 30, 2008 and December 31, 2007, approximately $2.7 million and $3.4 million, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets.

New Accounting Pronouncements. In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosures regarding fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements. SFAS No. 157 was effective for fiscal periods beginning after November 15, 2007. On February 12, 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. For Swift, this action defers the effective date for those assets and liabilities until January 1, 2009. The adoption of this statement is not expected to have a material impact on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure eligible assets and liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. This Statement, together with the International Accounting Standards Board's (IASB) IFRS 3, Business Combinations, completes a joint effort by the FASB and IASB to improve financial reporting about business combinations and promotes the international convergence of accounting standards. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We will evaluate the impact of SFAS No. 141(R) on business combinations and related valuations as we have business acquisitions in the future.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. This statement requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Since this statement only impacts disclosure requirements, the adoption of this statement will not have an impact on our financial position or results of operations.

12

(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, 2007, for additional information related to these share-based compensation plans.

We follow SFAS No. 123 (R), "Share-Based Payment" to account for share based compensation.

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. 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 $3.2 million and $0.7 million for the six months ended June 30, 2008 and 2007, respectively. The benefit for the first six months of 2008 that was not recognized in the financial statements as these benefits had not been realized through the estimated alternative minimum tax calculation was $2.1 million, and the benefit for the first six months of 2007 that was not recognized in the financial statements as these benefits had not been realized due to a tax net operating loss position for this period was $0.7 million.

Net cash proceeds from the exercise of stock options were $7.4 million and $1.6 million for the six months ended June 30, 2008 and 2007. The actual income tax benefit realized from stock option exercises was $3.5 million and $0.9 million for the same periods.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees, which was recorded in "General and administrative, net" in the accompanying condensed consolidated statements of income, was $3.1 million and $2.5 million for the quarters ended June 30, 2008 and 2007, respectively, and was $5.4 million and $4.6 million for the six month periods ended June 30, 2008 and 2007. Stock compensation recorded in lease operating cost was $0.2 million and $0.1 million for the quarters ended June 30, 2008 and 2007, respectively, and was $0.3 million for both of the six month periods ended June 30, 2008 and 2007, respectively. We also capitalized $1.2 million and $1.1 million of stock compensation in the second quarters of 2008 and 2007, respectively, and capitalized $2.3 million and $2.1 million of stock compensation in the six month periods ended June 30, 2008 and 2007, 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 service period 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 June 30,		Six Month Ended June 30,	
	2008	2007	2008	2007
Dividend yield	0%	0%	0%	0%
Expected volatility	38.4%	37.7%	38.9%	38.5%
Risk-free interest rate	2.5%	5.1%	2.5%	4.8%
Expected life of options (in years)	2.0	1.9	4.2	6.2

Weighted-average grant-date fair value	$ 13.89	$ 10.73	$ 15.53	$ 20.10

The expected term for grants issued during 2008 has been based on an analysis of historical employee exercise behavior and considered all relevant factors including expected future employee exercise behavior. The expected term for grants issued prior to 2008 was 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, we have used a 5.5 year look-back period to estimate expected volatility of our 2008 stock option grants, which is an increase from the four-year period used to estimate expected volatility for grants prior to 2008.

At June 30, 2008, there was $3.9 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.5 years. The following table represents stock option activity for the six months ended June 30, 2008:

	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,449,240	$ 28.47
Options granted	210,317	$ 47.18
Options canceled	(13,220)	$ 26.06
Options exercised	(452,044)	$ 25.45
Options outstanding, end of period	1,194,293	$ 32.90
Options exercisable, end of period	604,863	$ 27.53

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at June 30, 2008 was $39.6 million and 5.6 years and $23.3 million and 4.1 years, respectively. Total intrinsic value of options exercised during the six months ended June 30, 2008 was $12.4 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, 2007, 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 June 30, 2008, we had unrecognized compensation expense of approximately $17.6 million associated with these awards which are expected to be recognized over a weighted-average period of 1.9 years. The total fair value of shares vested during the first six months ended June 30, 2008 was $6.8 million.

The following table represents restricted stock activity for the six months ended June 30, 2008:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	596,590	$ 41.60
Restricted shares granted	295,600	$ 44.18
Restricted shares canceled	(22,042)	$ 42.43
Restricted shares vested	(165,886)	$ 41.16
Restricted shares outstanding, end of period	704,262	$ 42.73

(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 using the treasury stock method. Certain of our stock options and restricted stock that would potentially dilute Basic EPS in the future were also antidilutive for the periods ended June 30, 2008 and 2007, and are discussed below.

14

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and six month periods ended June 30, 2008 and 2007 (in thousands, except per share amounts):

	Three Months Ended June 30, 2008			Three Months Ended June 30, 2007		
	Income from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:						
Net Income from continuing operations, and Share Amounts	$ 83,245	30,608	$ 2.72	$ 30,523	29,930	$ 1.02
Dilutive Securities:						
Restricted Stock	--	330		--	168	
Stock Options	--	403		--	515	
Diluted EPS:						
Net Income from continuing operations, and assumed Share conversions	$ 83,245	31,341	$ 2.66	$ 30,523	30,613	$ 1.00

	Six Months Ended June 30, 2008			Six Months Ended June 30, 2007		
	Income from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:						
Net Income from continuing operations, and Share Amounts	$ 133,080	30,478	$ 4.37	$ 56,968	29,880	$ 1.91
Dilutive Securities:						
Restricted Stock	--	316		--	165	
Stock Options	--	355		--	509	
Diluted EPS:						
Net Income from continuing operations, and assumed Share conversions	$ 133,080	31,149	$ 4.27	$ 56,968	30,554	$ 1.86

Options to purchase approximately 1.2 million shares at an average exercise price of $32.90 were outstanding at June 30, 2008, while options to purchase 1.6 million shares at an average exercise price of $27.41 were outstanding at June 30, 2007. Approximately 0.8 million and 1.1 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended June 30, 2008 and 2007, respectively, and 0.8 million and 1.1 million options to purchase shares were not included in the computation of Diluted EPS for the six months ended June 30, 2008 and 2007, respectively, because these stock options were antidilutive, in that the sum of the stock 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 0.4 million and 0.5 million shares were not included in the computation of Diluted EPS for the three months ended June 30, 2008 and 2007, respectively, and 0.4 million and 0.5 million were not included in the computation of Diluted EPS for the six months ended June 30, 2008 and 2007, respectively, because these restricted stock grants were antidilutive 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 as of June 30, 2008 and December 31, 2007, was as follows (in thousands):

	June 30, 2008	December 31, 2007
Bank Borrowings	$ 124,200	$ 187,000
7-5/8% senior notes due 2011	150,000	150,000
7-1/8% senior notes due 2017	250,000	250,000
Long-Term Debt	$ 524,200	$ 587,000

Bank Borrowings. At June 30, 2008, we had borrowings of $124.2 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $400.0 million, based entirely on assets from continuing operations, and expires in October 2011. The interest rate is either (a) the lead bank's prime rate (5.0% at June 30, 2008) 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 April 2007 we increased the borrowing base to $350.0 million from $250.0 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 covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred an additional $0.3 million of debt issuance costs related to the increase of the commitment amount in 2007, which is included in "Debt issuance costs" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense over the life of the facility.

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 natural gas properties. Under the terms of the 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. The borrowing base amount is re-determined at least every six months and the next scheduled borrowing base review is in November 2008.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $2.6 million and $1.1 million for the three months ended June 30, 2008 and 2007, respectively, and $5.4 million and $2.6 million for the six months ended June 30, 2008 and 2007, respectively. The amount of commitment fees included in interest expense, net was $0.1 million and $0.1 million for the three month periods ended June 30, 2008 and 2007, respectively, and $0.2 million and $0.2 million for the six month periods ended June 30, 2008 and 2007.

Senior Notes Due 2011. These notes consist of $150.0 million of 7-5/8% senior notes, 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.

16

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. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying consolidated 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 June 30, 2008 and 2007, respectively, and $6.0 million for each of the six month periods ended June 30, 2008 and 2007.

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. 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 $4.1 million and $8.9 million for the three and six month periods ended June 30, 2007.

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, 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 $1.5 million for the three month periods ended June 30, 2008 and 2007, respectively, and $9.1 million and $1.5 million for the six month periods ended June 30, 2008 and 2007, respectively.

The maturities on our long-term debt are $0 for 2008, 2009 and 2010, $274.2 million for 2011, and $250 million thereafter.

17

We have capitalized interest on our unproved properties in the amount of $2.0 million and $2.4 million for the three months ended June 30, 2008 and 2007, respectively, and $3.9 million and $5.0 million for the six month periods ended June 30, 2008 and 2007, respectively.

(6) Discontinued Operations

In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In May 2008, we agreed to sell our remaining New Zealand permit for $15.0 million; with three $5.0 payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale; with the sale expected to close in 2008. All payments under this sale agreement are secured by unconditional letters of credit.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheet for prior periods. During the fourth quarter of 2007 and the first half of 2008, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement in place at that time and recorded non-cash asset write-downs of $143.2 million and $3.3 million, respectively, related to these assets. These write-downs are recorded in "Income (loss) from discontinued operations, net of taxes" on the accompanying condensed consolidated statements of income.

The book value of our remaining New Zealand permit is approximately $0.6 million at June 30, 2008.

The following table summarizes the amounts included in "Income (loss) from discontinued operations, net of taxes" for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported as discontinued operations (in thousands except per share amounts):

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Oil and gas sales	$ 6,370	$ 11,363	$ 14,675	$ 22,170
Other revenues	207	500	781	707
Total revenues	6,577	11,863	15,456	22,877
Depreciation, depletion, and amortization	2,289	5,825	4,909	11,750
Other operating expenses	4,241	5,754	10,136	10,027
Non-cash write-down of property and equipment	1,200	---	3,296	---
Total expenses	7,730	11,579	18,341	21,777
Income (loss) from discontinued operations before income taxes	(1,153)	284	(2,885)	1,100
Income tax expense (benefit)	173	(703)	(85)	(1,030)
Income (loss) from discontinued operations, net of taxes	$ (1,326)	$ 987	$ (2,800)	$ 2,130

Income (loss) per common share from discontinued operations-diluted	$	(0.04)	$	0.03	$	(0.09)	$	0.07
Sales volumes (MBoe)		167		371		415		755
Cash flow provided by operating activities	$	3,868	$	5,280	$	6,690	$	12,672
Capital expenditures	$	990	$	557	$	2,013	$	7,536

Total New Zealand assets were $13.9 million at June 30, 2008 and $110.6 million at December 31, 2007. Our capitalized general and administrative expenses were immaterial in the 2008 period and totaled $1.2 million and $2.4 million for the three months and six months ended June 30, 2007, respectively.

As of June 30, 2008, we held $0.6 million of property and equipment, net in “Current assets held for sale”, and at December 31, 2007, we held $96.5 million of property and equipment, net in “Current assets held for sale” and $8.1 million of asset retirement obligations in “Current liabilities associated with assets held for sale” on the accompanying condensed consolidated balance sheets.

(7) Acquisitions and Dispositions

In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP. 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 refer to these properties as the Cotulla properties. We paid approximately $248.2 million in cash for these interests including purchase price adjustments. After taking into account internal acquisition costs of $2.5 million, our total cost was $250.7 million. We allocated $241.8 million of the acquisition price to “Proved Properties,” $8.9 million to “Unproved Properties,” and recorded a liability for $0.6 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 Texas. The revenues and expenses from these properties have been included in our accompanying condensed consolidated statement of income from the date of acquisition forward; however, given that the acquisitions closed in the fourth quarter of 2007, these amounts were not material to our full year 2007 results.

(8) Condensed Consolidating Financial Information

Both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) are co-obligors of the 7-5/8% Senior Notes due 2011. The co-obligations on these notes 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 other subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands)	June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 132,914	$ 13,893	$ ---	$ 146,807
Property and equipment	---	1,950,240	179	---	1,950,419
Investment in subsidiaries (equity method)	982,679	---	909,583	(1,892,262)	---
Other assets	---	8,516	61,588	(61,588)	8,516
Total assets	$ 982,679	$ 2,091,670	$ 985,243	$ (1,953,850)	$ 2,105,742
LIABILITIES AND STOCKHOLDERS’ EQUITY					
Current liabilities	$ ---	$ 185,822	$ 2,649	$ ---	$ 188,471
Long-term liabilities	---	996,265	(85)	(61,588)	934,592
Stockholders’ equity	982,679	909,583	982,679	(1,892,262)	982,679

Total liabilities and stockholders’ equity	$ 982,679	$ 2,091,670	$ 985,243	$ (1,953,850)	$ 2,105,742

(in thousands)	December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 89,513	$ 110,437	$ ---	$ 199,950
Property and equipment	---	1,760,195	---	---	1,760,195
Investment in subsidiaries (equity method)	836,054	---	760,158	(1,596,212)	---
Other assets	---	28,828	---	(19,922)	8,906
Total assets	$ 836,054	$ 1,878,536	$ 870,595	$ (1,616,134)	$ 1,969,051
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 195,542	$ 34,541	$ (19,922)	$ 210,161
Long-term liabilities	---	922,836	---	---	922,836
Stockholders' equity	836,054	760,158	836,054	(1,596,212)	836,054
Total liabilities and stockholders' equity	$ 836,054	$ 1,878,536	$ 870,595	$ (1,616,134)	$ 1,969,051

Condensed Consolidating Statements of Income

(in thousands)	Three Months Ended June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 262,681	$ ---	$ ---	$ 262,681
Expenses	---	131,709	---	---	131,709
Income before the following:	---	130,972	---	---	130,972
Equity in net earnings of subsidiaries	81,919	---	83,245	(165,164)	---
Income from continuing operations, before income taxes	81,919	130,972	83,245	(165,164)	130,972
Income tax provision	---	47,727	---	---	47,727
Income from continuing operations	81,919	83,245	83,245	(165,164)	83,245
Loss from discontinued operations, net of taxes	---	---	(1,326)	---	(1,326)
Net income	$ 81,919	$ 83,245	$ 81,919	$ (165,164)	$ 81,919

(in thousands)	Six Months Ended June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 461,641	$ ---	$ ---	$ 461,641
Expenses	---	251,827	---	---	251,827
Income before the following:	---	209,814	---	---	209,814
Equity in net earnings of subsidiaries	130,280	---	133,080	(263,360)	---
Income from continuing operations, before income taxes	130,280	209,814	133,080	(263,360)	209,814
Income tax provision	---	76,734	---	---	76,734
Income from continuing operations	130,280	133,080	133,080	(263,360)	133,080
Loss from discontinued operations, net of taxes	---	---	(2,800)	---	(2,800)
Net income	$ 130,280	$ 133,080	$ 130,280	$ (263,360)	$ 130,280

(in thousands)	Three Months Ended June 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 156,410	$ ---	$ ---	$ 156,410
Expenses	---	107,853	---	---	107,853
Income before the following:	---	48,557	---	---	48,557
Equity in net earnings of subsidiaries	31,510	---	30,523	(62,033)	---
Income from continuing operations, before income taxes	31,510	48,557	30,523	(62,033)	48,557
Income tax provision	---	18,034	---	---	18,034
Income from continuing operations	31,510	30,523	30,523	(62,033)	30,523
Income from discontinued operations, net of taxes	---	---	987	---	987
Net income	$ 31,510	$ 30,523	$ 31,510	$ (62,033)	$ 31,510

(in thousands)	Six Months Ended June 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 286,489	$ ---	$ ---	$ 286,489
Expenses	---	196,015	---	---	196,015
Income before the following:	---	90,474	---	---	90,474
Equity in net earnings of subsidiaries	$ 59,098	---	56,968	(116,066)	---
Income from continuing operations, before income taxes	59,098	90,474	56,968	(116,066)	90,474
Income tax provision	---	33,506	---	---	33,506
Income from continuing operations	59,098	56,968	56,968	(116,066)	56,968
Income from discontinued operations, net of taxes	---	---	2,130	---	2,130
Net income	$ 59,098	$ 59,968	$ 59,098	$ (116,066)	$ 59,098

Condensed Consolidating Statements of Cash Flow

(in thousands)	Six Months Ended June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 294,743	$ 6,690	$ ---	$ 301,433
Cash flow from investing activities	---	(236,936)	80,731	(81,913)	(238,118)
Cash flow from financing activities	---	(55,791)	(81,913)	81,913	(55,791)
Net increase in cash	---	2,016	5,508	---	7,524
Cash, beginning of period	---	180	5,443	---	5,623
Cash, end of period	$ ---	$ 2,196	$ 10,951	$ ---	$ 13,147

(in thousands)	Six Months Ended June 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	$ ---	$ 193,383	$ 12,672	$ ---	$ 206,055
Cash flow from investing activities	---	(195,009)	(7,536)	(3,664)	(206,209)
Cash flow from financing activities	---	6,312	(3,664)	3,664	6,312
Net increase in cash	$ ---	$ 4,686	$ 1,472	$ ---	$ 6,158
Cash, beginning of period	---	50	1,008	---	1,058
Cash, end of period	$ ---	$ 4,736	$ 2,480	$ ---	$ 7,216

MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS 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, 2007. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 34 of this report.

Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relate solely to our continuing operations located in the United States, and exclude our discontinued New Zealand operations.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on reserves and production in the inland waters of Louisiana and from our onshore Louisiana and Texas properties.

We are the largest producer of oil in the state of Louisiana, and due to our South Louisiana operations, we are predominantly an oil producer, with oil constituting 55% of our second quarter 2008 production, and oil and natural gas liquids ("NGLs") together making up 66% of our second quarter 2008 production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in recent periods.

In the second quarter of 2008 we had record income and cash flows. Income from continuing operations increased 173% to $83.2 million and cash flows from operating activities from continuing operations increased 35% to $155.1 million, in each case compared to the second quarter of 2007. Production from our continuing operations increased 4% to 2.69 MMBoe, due to increased production in our South Texas regions offset by production declines in our South Louisiana region. We also had record quarterly revenues of $262.7 million for the second quarter of 2008, an increase of 68% over comparable 2007 levels. Our weighted average sales price received increased 62% to $97.70 per Boe for the second quarter of 2008 from $60.37 received during the second quarter of 2007. Our $106.9 million, or 68%, increase in oil and gas sales revenues resulted from 89% higher oil prices, 53% higher NGL prices, and 39% higher natural gas prices during the 2008 period.

During the second quarter of 2008, our overall costs and expenses increased 22% when compared to those costs in the same 2007 period. The largest increase in these costs and expenses was attributable to 31% higher depreciation, depletion and amortization expense, due to our larger depletable property base and higher production volumes. Lease operating expense increased 77% due to higher workover costs, as we increased the number of workovers performed in the current period, a higher well count mainly from our South Texas property acquisition in late 2007, and higher NGL and natural gas processing costs. Severance and other taxes also increased 51% mainly due to increased oil and gas revenues. We expect cost pressures to continue to affect the industry throughout the remainder of 2008, with tightening availability of experienced crews and personnel as well as increasing costs of services, goods, and basic equipment. In the inflationary cost environment prevalent in the industry today, we will continue to focus on capital efficiency to manage those costs and expenses.

Lake Washington is our most significant field, and provides approximately 47% of our production. In the second quarter of 2008, production at Lake Washington fell 3% from first quarter 2008 levels, and year to date production in 2008 fell 25% when compared to year to date 2007 levels. At Lake

Washington in the second quarter, along with experiencing natural declines, we reduced the choke size of several wells in the Newport area to manage reservoir pressure in anticipation of the pressure maintenance program that commenced with the West Side facility start-up early in the second quarter of 2008. Although pressure maintenance was commenced during the quarter, the required water injection volumes have not yet been achieved. We are moving forward with converting some existing wells and drilling additional wells to enable higher water injection volumes to be achieved. Deeper wells with higher flowing pressures and higher gas-to-oil ratios continue to be drilled at Lake Washington. The increased pressure from the newer wells coupled with increasing volumes of associated gas, has increased the over-all operating pressure in the field's bulk gathering lines and production facilities, negatively impacting production rates from the more mature, lower flowing pressure wells. Additionally, higher volumes of produced water from older more mature wells are being handled with oil production in the field, causing higher artificial lift demand from the mature areas of the field. As a result, we designed and permitted additional gathering lines during the second quarter that are intended to provide additional flexibility to the gathering system. These new lines will be used to segregate newer wells from the older more mature wells, thereby reducing the back pressure of the older wells and maintaining higher production rates from these older wells. The first additional line is being installed between Newport and the West Side facility and is expected to be operational in the third quarter. Additional lines have also been designed and will be installed later this year. We anticipate that pressure maintenance activities planned for 2008, together with the West Side infrastructure enhancements, will reduce the production constraints experienced in the first half of 2008. In Bay de Chene, we signed a new marketing agreement in the first quarter of 2008 and increased takeaway capacity early in the second quarter. This increase in takeaway capacity led to increased production in this area during second quarter and is expected for the remainder of 2008.

In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In May 2008, we agreed to sell our remaining New Zealand permit for $15.0 million; with three $5.0 payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale; with the sale expected to close in the third quarter of 2008. All payments under this sale agreement are secured by unconditional letters of credit. Accordingly, our New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. Upon closing of the sale of our remaining permit, we expect to record a non-cash gain of approximately $12.8 million.

Our debt to capitalization ratio decreased to 35% at June 30, 2008, as compared to 41% at year-end 2007, as proceeds from our June 2008 New Zealand asset sale were used to pay down a portion of our credit facility. Our debt to PV-10 ratio decreased to 8% at June 30, 2008 from 15% at year-end 2007, due to higher period-end reserves prices and lower borrowings against our line of credit at that date.

Our capital expenditures for continuing operations of $142.6 million increased by $53.5 million during the second quarter of 2008 as compared to the same period in 2007, primarily due to an increase in our spending on drilling and development, predominantly in our South Louisiana and South Texas regions. These expenditures were funded by $155.1 million of cash provided by operating activities from continuing operations.

Our current 2008 capital expenditure budget is $525 million to $575 million, net of minor non-core dispositions and excluding any property acquisitions, which was recently increased from $475 million to $525 million. Based upon current market conditions, commodity prices, and our estimates, our capital expenditures for 2008 should be within our anticipated cash flow from operations. We currently have budgeted approximately two-thirds of these amounts for our South Louisiana region, and on an overall basis three-fourths for developmental activities. For the full year 2008, we are targeting production from our continuing operations to increase 2% to 5% and domestic proved reserves to increase 5% to 9% both over 2007 levels. We may also further increase our capital expenditure budget if commodity prices rise during the year or if strategic opportunities warrant. If 2008 capital expenditures exceed our cash flow from operating activities, we can fund these expenditures with funds drawn under our credit facility.

24

Also in the Lake Washington and Bay de Chene area, we completed our 3D seismic depth migration of the merged data sets with an updated "salt model." We also completed our seismic "pore-pressure" prediction project. This has allowed us to increase our confidence level as we begin to drill some of the deeper and higher impact wells in this area of South Louisiana. For example, we are currently drilling our Shasta prospect and preparing to drill our Teton and West Newport prospects. A full inventory of deeper and higher impact tests will be underway this year and carry over into 2009 drilling. In South Louisiana, we will continue to drill deeper, impactful well targets identified through our 3D seismic library. This includes developing and planning a sub-salt exploratory test, most likely next year.

Results of Continuing Operations — Three Months Ended June 30, 2008 and 2007

Revenues. Our revenues in the second quarter of 2008 increased by 68% compared to revenues in the same period in 2007, due to higher commodity prices. Revenues for both periods were substantially comprised of oil and gas sales. Crude oil production was 55% of our production volumes in the second quarter of 2008 and 72% of our production in the second quarter of 2007. Natural gas production was 34% of our production volumes in the second quarter of 2008 and 23% in the second quarter of 2007.

Our domestic areas are divided into the following regions: The Lake Washington region includes the Lake Washington and Bay de Chene areas. The North Lafayette region includes the Brookeland, Masters Creek, and South Bearhead Creek areas. The South Lafayette region includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, and Bayou Penchant areas. The South Texas region includes the AWP Olmos and Cotulla areas. The most significant property in our other category is the High Island area. The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the three months ended June 30, 2008 and 2007:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (MBoe)	
	2008	2007	2008	2007
Lake Washington/Bay de Chene	$ 165.3	$ 118.6	1,470	1,897
North Lafayette	25.8	11.5	257	202
South Lafayette	20.9	9.6	233	171
South Texas	47.3	14.3	678	285
Other	3.9	2.3	56	34
Total	$ 263.2	$ 156.3	2,694	2,589

Oil and gas sales for the second quarter of 2008 increased by 68%, or $106.9 million, from the level of those revenues for the comparable 2007 period, and our net sales volumes in the second quarter of 2008 increased by 4%, or 0.1 MMBoe, over net sales volumes in the second quarter of 2007. Average prices for oil increased to $125.20 per Bbl in the second quarter of 2008 from $66.20 per Bbl in the second quarter of 2007. Average natural gas prices increased to $10.49 per Mcf in the second quarter of 2008 from $7.56 per Mcf in the second quarter of 2007. Average NGL prices increased to $67.73 per Bbl in the second quarter of 2008 from $44.22 per Bbl in the second quarter of 2007.

In the second quarter of 2008, our $106.9 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $110.5 million favorable impact on sales, of which $87.5 million was attributable to the 89% increase in average oil prices received, $6.8 million was attributable to the 53% increase in NGL prices, and $16.2 million was attributable to the 39% increase in natural gas prices; and

-

Volume variances that had a $3.6 million unfavorable impact on sales, with $25.8 million of decreases attributable to the 0.4 million Bbl decrease in oil sales volumes, offset by a $6.8 million increase due to the 0.2 million Bbl increase in NGL sales volumes, and a $15.4 million increase due to the 2.0 Bcf increase in natural gas sales volumes.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations excluding any effects of our hedging activities:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural gas (Mcf)
Three Months Ended June 30, 2008	1,482	290	5.5	2,694	$125.20	$67.73	$10.49
Three Months Ended June 30, 2007	1,872	134	3.5	2,589	$66.20	$44.22	$7.56

During the second quarters of 2008 and 2007, we recognized net losses of $0.9 million and $0.4 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. Had these losses been recognized in the oil and gas sales account, our average oil sales price would have been $125.15 and $66.20 for the second quarters of 2008 and 2007, respectively, and our average natural gas sales price would have been $10.34 and $7.44 for the second quarters of 2008 and 2007, respectively.

Costs and Expenses. Our expenses in the second quarter of 2008 increased $23.9 million, or 22%, compared to expenses in the same period of 2007.

Our second quarter 2008 general and administrative expenses, net, increased $0.7 million, or 7%, from the level of such expenses in the same 2007 period. The increase was primarily due to increased salaries and burdens associated with our expanded workforce and was partially offset by higher capitalized amounts and an increase in supervision fee reimbursements as we operated more wells in the 2008 period due to the acquisition of the Cotulla properties and increases in reimbursement rates. For the second quarters of 2008 and 2007, our capitalized general and administrative costs totaled $7.9 million and $5.9 million, respectively. Our net general and administrative expenses per Boe produced increased to $3.82 per Boe in the second quarter of 2008 from $3.72 per Boe in the second quarter of 2007. The portion of supervision fees recorded as a reduction to general and administrative expenses was $3.9 million and $2.6 million for three month periods ended June 30, 2008 and 2007, respectively.

DD&A increased $13.4 million, or 31%, in the second quarter of 2008, from levels in the second quarter of 2007. The increase is due to increases in the depletable oil and natural gas property base, and higher production. Industry costs for services and goods have increased over the last three year period and have contributed to the increase in our DD&A expense. Our DD&A rate per Boe of production was $21.26 and $16.94 in the second quarters of 2008 and 2007, respectively, resulting from increases in the per unit cost of reserves additions.

We recorded $0.5 million and $0.3 million of accretions to our asset retirement obligation in the second quarters of 2008 and 2007, respectively.

Our lease operating costs increased $12.4 million, or 77%, over the level of such expenses in the same 2007 period. Lease operating costs increased during 2008 due to increased workover costs, additional costs from the Cotulla properties acquired in the fourth quarter of 2007, increasing costs for industry goods and services, and higher natural gas and NGL processing costs in 2008. Our lease operating costs per Boe produced were $10.61 and $6.25 in the second quarters of 2008 and 2007, respectively.

Severance and other taxes increased $9.1 million, or 51%, over levels in the second quarter of 2007. The increase in the 2008 period was due primarily to increased oil and gas revenues that resulted from higher commodity prices. Severance and other taxes as a percentage of oil and gas sales were approximately 10.2% and 11.4% in the second quarters of 2008 and 2007, respectively. 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 decreased as a percentage of overall production in the second quarter of 2008 compared to the second quarter of 2007, the overall percentage of severance costs to sales also decreased.

Our total interest cost in the second quarter of 2008 was $10.2 million, of which $2.0 million was capitalized. Our total interest costs in the second quarter of 2007 were $9.7 million, of which $2.4 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the second quarter of 2008 was primarily attributable to increase borrowings against our line of credit and lower capitalized costs, partially offset by lower interest expense resulting from our 2007 debt refinancing.

In the second quarter of 2007, we recorded $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 a $3.4 million write-off of unamortized debt issuance costs.

Our overall effective tax rate was 36.4% and 37.1% for the second quarters of 2008 and 2007, respectively. The effective tax rate for the second quarters of 2008 and 2007 were higher than the U.S. federal statutory rate of 35% primarily because of state income taxes.

Income from Continuing Operations. Our income from continuing operations for the second quarter of 2008 of $83.2 million was 173% higher than second quarter of 2007 income from continuing operations of $30.5 million due to higher commodity prices which were partially offset by increased costs.

Net Income. Our net income in the second quarter of 2008 of $81.9 million was 160% higher than our second quarter of 2007 net income of $31.5 million, mainly due to higher commodity prices which were partially offset by increased costs.

Results of Continuing Operations — Six months Ended June 30, 2008 and 2007

Revenues. Our revenues in the first six months of 2008 increased by 62% compared to revenues in the same period in 2007, due to higher commodity prices. Crude oil production was 55% of our production volumes in the first six months of 2008 and 71% of our production in the first six months of 2007. Natural gas production was 33% of our production volumes in the first six months of 2008 and 24% in the first six months of 2007.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the six months ended June 30, 2008 and 2007:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (MBoe)	
	2008	2007	2008	2007
Lake Washington/Bay de Chene	$294.0	$215.2	2,935	3,642
North Lafayette	43.7	19.1	484	377
South Lafayette	32.8	20.5	393	403
South Texas	85.7	26.8	1,344	598
Other	7.0	4.9	108	103
Total	$463.2	$286.5	5,264	5,123

Oil and gas sales for the first six months of 2008 increased by 62%, or $176.6 million, from the level of those revenues for the comparable 2007 period, and our net sales volumes in the first six months of 2008 increased by 3%, or 0.1 MMBoe, over net sales volumes in the first six months of 2007. Average prices for oil increased to $112.59 per Bbl in the first six months of 2008 from $62.14 per Bbl in the first six months of 2007. Average natural gas prices increased to $9.29 per Mcf in the first six months of 2008 from $6.71 per Mcf in the first six months of 2007. Average NGL prices increased to $63.60 per Bbl in the first six months of 2008 from $42.07 per Bbl in the first six months of

2007.

In the first six months of 2008, our $176.6 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $186.6 million favorable impact on sales, of which $146.4 million was attributable to the 81% increase in average oil prices received, $13.0 million was attributable to the 51% increase in NGL prices, and $27.2 million was attributable to the 38% increase in natural gas prices.

- Volume variances that had a $10.0 million unfavorable impact on sales, with $46.2 million of decreases attributable to the 0.7 million Bbl decrease in oil sales volumes, offset by a $14.2 million increase due to the 0.3 million Bbl increase in NGL sales volumes, and a $22.0 million increase due to the 3.3 Bcf increase in natural gas sales volumes; and

The following table provides additional information regarding our first six months of 2008 and 2007 oil and gas sales from continuing operations excluding any effects of our hedging activities:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural gas (Mcf)
Six months Ended June 30, 2008	2,901	606	10.5	5,264	$112.59	$63.60	$9.29
Six months Ended June 30, 2007	3,645	267	7.3	5,123	$62.14	$42.07	$6.71

During the first six months of 2008 and 2007, we recognized net losses of $1.9 million and $0.7 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. Had these losses been recognized in the oil and gas sales account, our average oil sales price would have been $112.36 and $62.14 for the first six months of 2008 and 2007, respectively, and our average natural gas sales price would have been $9.17 and $6.61 for the first six months of 2008 and 2007, respectively.

Costs and Expenses. Our expenses in the first six months of 2008 increased $55.8 million, or 28%, compared to expenses in the same period of 2007.

Our first six months of 2008 general and administrative expenses, net, increased $3.0 million, or 17%, from the level of such expenses in the same 2007 period. The increase was primarily due to increased salaries and burdens associated with our expanded workforce and was partially offset by higher capitalized amounts and an increase in supervision fee reimbursements as we operated more wells in the 2008 period due to the acquisition of the Cotulla properties and increases in reimbursement rates. For the first six months of 2008 and 2007, our capitalized general and administrative costs totaled $14.7 million and $13.1 million, respectively. Our net general and administrative expenses per Boe produced increased to $3.84 per Boe in the first six months of 2008 from $3.36 per Boe in the first six months of 2007. The portion of supervision fees recorded as a reduction to general and administrative expenses was $7.8 million and $5.2 million for six month periods ended June 30, 2008 and 2007, respectively.

DD&A increased $24.2 million, or 28%, in the first six months of 2008 from levels in the first six months of 2007. The increase is due to increases in the depletable oil and natural gas property base, and higher production. Industry costs for services and goods have increased over the last three year period and have contributed to the increase in our DD&A expense. Our DD&A rate per Boe of production was $20.85 and $16.70 in the first six months of 2008 and

2007, respectively, resulting from increases in the per unit cost of reserves additions.

We recorded $0.9 million and $0.7 million of accretions to our asset retirement obligation in the first six months of 2008 and 2007, respectively.

Our lease operating costs increased $23.1 million, or 72%, over the level of such expenses in the same 2007 period. Lease operating costs increased during 2008 due to increased workover costs, additional costs from the Cotulla properties acquired in the fourth quarter of 2007, increasing costs for industry goods and services, and higher natural gas and NGL processing costs in 2008. Our lease operating costs per Boe produced were $10.45 and $6.22 in the first six months of 2008 and 2007, respectively.

Severance and other taxes increased $15.2 million, or 45%, over levels in the first six months of 2007. The increase in the 2008 period was due primarily to increased oil & gas revenues due to higher commodity prices along with an increase in ad valorem tax expense. Severance and other taxes as a percentage of oil and gas sales were approximately 10.6% and 11.8% in the first six months of 2008 and 2007, respectively. 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 decreased as a percentage of overall production in the first six months of 2008 compared to the first six months of 2007, the overall percentage of severance costs to sales also decreased.

Our total interest cost in the first six months of 2008 was $20.8 million, of which $3.9 million was capitalized. Our total interest cost in the first six months of 2007 was $19.0 million, of which $5.0 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the first six months of 2008 was primarily attributable to increased borrowings against our line of credit and lower capitalized costs, partially offset by lower interest expense resulting from our 2007 debt refinancing.

In the 2007 period, we recorded $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 a $3.4 million write-off unamortized debt issuance costs.

Our overall effective tax rate was 36.6% and 37.0% for the first six months of 2008 and 2007. The effective tax rate for the first six months of 2008 and 2007 were higher than the U.S. federal statutory rate of 35% primarily because of state income taxes.

Income from Continuing Operations. Our income from continuing operations for the first six months of 2008 of $133.1 million was 134% higher than first six months of 2007 income from continuing operations of $57.0 million due to higher commodity prices which were partially offset by increased costs.

Net Income. Our net income in the first six months of 2008 of $130.3 million was 120% higher than our first six months of 2007 net income of $59.1 million, mainly due to higher commodity prices which were partially offset by increased costs.

Significant Accounting Policies

Our significant accounting policies are discussed in our Annual Report on Form 10-K for the year ending December 31, 2007.

Discontinued Operations

In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In May 2008, we agreed to sell our remaining New Zealand permit for $15.0 million; with three $5.0 payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale; with the sale expected to close in 2008. All payments under this sale agreement are secured by unconditional letters of credit.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheet for prior periods. During the fourth quarter of 2007 and the first half of 2008, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement in place at that time and recorded non-cash asset write-downs of $143.2 million and $3.3 million, respectively, related to these assets. These write-downs are recorded in "Income (loss) from discontinued operations, net of taxes" on the accompanying condensed consolidated statement of income.

The book value of our remaining New Zealand permit is approximately $0.6 million, and we expect to record a non-cash gain of $12.8 million upon closing the sale of that permit.

As of June 30, 2008, operations in New Zealand had represented less than 1% of our total assets and approximately 6% and 7% of our second quarter 2008 and first six months of 2008 sales volumes, respectively. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported under discontinued operations. The following table summarizes selected data pertaining to discontinued operations (in thousands except per share and per Boe amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Oil and gas sales	$ 6,370	$ 11,363	$ 14,675	$ 22,170
Other revenues	207	500	781	707
Total revenues	6,577	11,863	15,456	22,877
Depreciation, depletion, and amortization	2,289	5,825	4,909	11,750
Other operating expenses	4,241	5,754	10,136	10,027
Non-cash write-down of property and equipment	1,200	---	3,296	---
Total expenses	7,730	11,579	18,341	21,777
Income (loss) from discontinued operations before income taxes	(1,153)	284	(2,885)	1,100
Income tax expense (benefit)	173	(703)	(85)	(1,030)
Income (loss) from discontinued operations, net of taxes	$ (1,326)	$ 987	$ (2,800)	$ 2,130
Income (loss) per common share from discontinued operations, net of taxes-diluted	$ (0.04)	$ 0.03	$ (0.09)	$ 0.07
Total sales volumes (MBoe)	167	371	415	755
Oil sales volumes (MBbls)	24	62	58	124
Natural gas sales volumes (Bcf)	0.7	1.6	1.8	3.2
NGL sales volumes (MBbls)	20	48	52	96

Average sales price per Boe	$	38.15	$	30.67	$	35.37	$	29.37
Oil sales price per Bbl	$	126.29	$	75.17	$	108.16	$	69.57
Natural gas sales price per Mcf	$	3.56	$	3.36	$	3.55	$	3.36
NGL sales price per Bbl	$	36.99	$	30.47	$	37.66	$	28.72
Lease operating cost per Boe	$	14.36	$	10.64	$	14.49	$	8.66
Cash flow provided by operating activities	$	3,868	$	5,280	$	6,690	$	12,672
Capital expenditures	$	990	$	557	$	2,013	$	7,536

Total New Zealand assets at June 30, 2008 and December 31, 2007 were $13.9 million and $110.6 million, respectively.

Income (loss) from discontinued operations, net of tax, for the second quarter of 2008 decreased compared to the same period of 2007 primarily due a decrease in produced oil and natural gas volumes which reduced revenues and a non-cash write-down of property and equipment, partially offset by lower depletion expense due to lower production volumes. Our capitalized general and administrative expenses were immaterial in the 2008 period and totaled $1.2 million and $2.4 million for the three months and six months ended June 30, 2007, respectively.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2007 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, 2007.

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 over the last three years and is at historical highs 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, can cause fluctuations in the price of oil. Domestic natural gas prices continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, the level of liquefied natural gas imports, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Liquidity and Capital Resources

During the first six months of 2008, we relied upon our net cash provided by operating activities from continuing operations of $294.7 million, cash proceeds from the sale of most of our New Zealand assets of $82.7 million, and cash balances to fund capital expenditures of $319.0 million and to pay down a portion of our credit facility. During the first six months of 2007, we relied upon our net cash provided by operating activities from continuing operations of $193.4 million and cash balances to fund capital expenditures of $199.4 million.

Net Cash Provided by Operating Activities. For the first six months of 2008, our net cash provided by operating activities from continuing operations was $ 294.7 million, representing a 52% increase as compared to $193.4 million generated during the first six months of 2007. The $101.4 million increase in 2008 was primarily due to an increase of $176.6 million in oil and gas sales, attributable to higher commodity prices, offset in part by lower oil production and increased expenses.

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 June 30, 2008 and December 31, 2007 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 Credit Facility. We had borrowings of $124.2 million under our bank credit facility at June 30, 2008, and $187.0 million in borrowings at December 31, 2007. Our bank credit facility at June 30, 2008 consisted 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 was increased by our bank group from $350.0 million to $400.0 million in November 2007. Under the terms of our bank 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. 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. 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.

Debt Maturities. Our credit facility, with a balance of $124.2 million at June 30, 2008, 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 decreased from a deficit of $10.2 million at December 31, 2007, to a deficit of $41.7 million at June 30, 2008. The decrease primarily resulted from a decrease in current assets held for sale as we closed the sale of substantially all of our New Zealand assets during the second quarter of 2008, partially offset by a decrease in current liabilities associated with assets held for sale due to the New Zealand asset sale and an increase in oil and gas sales receivables due to increased commodity prices, along with a higher cash balance, lower accrued capital costs and a decrease in undistributed oil and gas revenues.

Capital Expenditures. During the first six months of 2008, we relied upon our net cash provided by operating activities from continuing operations of $294.7 million, cash proceeds from the sale of most of our New Zealand assets of $82.7 million, and cash balances to fund capital expenditures of $319.0 million and to pay down a portion of our credit facility.

We have spent considerable time and capital on facility capacity upgrades and additions in the Lake Washington field. Our fourth production platform, the West Side facility, was commissioned in the second quarter of 2008 and has increased our crude oil processing capacity another 10,000 barrels per day.

We completed 60 of 63 wells in the first half of 2008, for a success rate of 95%. A total of 11 development wells were drilled successfully in the Lake Washington area, and 21 development wells were drilled in the AWP Olmos area, of which 20 were successful. In Bay de Chene, we successfully drilled two development wells. We also drilled four successful development wells in the South Bearhead Creek area, drilled 18 of 19 development wells in the Cotulla area, drilled one successful development well in the Horseshoe Bayou/Bayou Sale area, drilled two successful wells in the Jeanerette field, drilled one successful non-operated well in Alabama, and drilled one unsuccessful development well in the Masters Creek field. One successful exploratory well was also drilled in the Cote Blanche Island field.

During the last six months of 2008, we anticipate drilling or participating in the drilling of up to an additional 13 to 20 wells in the Lake Washington core area, an additional 20 to 27 wells in the South Texas core area, one to two wells in the Lafayette South core area, and two to four wells in the LaFayette North core area.

New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosures regarding fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements. SFAS No. 157 was effective for fiscal periods beginning after November 15, 2007. On February 12, 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. For Swift, this action defers the effective date for those assets and liabilities until January 1, 2009. The adoption of this statement is not expected to have a material impact on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure eligible assets and liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. This Statement, together with the International Accounting Standards Board's (IASB) IFRS 3, Business Combinations, completes a joint effort by the FASB and IASB to improve financial reporting about business combinations and promotes the international convergence of accounting standards. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We will evaluate the impact of SFAS No. 141(R) on business combinations and related valuations as we have business acquisitions in the future.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. This statement requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Since this statement only impacts disclosure requirements, the adoption of this statement will not have an impact on our 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 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, acquisition plans, 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 th uncertainty of future 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 from those projected. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices; availability of services and supplies; disruption of operations and damages due to hurricanes or tropical storms; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for and availability of 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 in this report and set forth from time to time in our other public reports, filings, and public statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- Price Floors – At June 30, 2008, we had in place price floors in effect through the December 2008 contract month for crude oil and natural gas. The oil price floors cover notional volumes of 1,530,000 barrels, with a weighted average floor price of $96.20 per barrel. Our oil price floors in place at June 30, 2008, are expected to cover approximately 49% to 54% of our oil production during the third and fourth quarters of 2008. The natural gas price floors cover notional volumes of 6,450,000 MMBtu, with a weighted average floor price of $9.23 per MMBtu. Our natural gas price floors in place at June 30, 2008, are expected to cover approximately 48% to 53% of our natural gas production during the third and fourth quarters of 2008. The fair value of these instruments at June 30, 2008, was $1.1 million and is recognized on the accompanying balance sheet in "Other current assets." There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be recognized on our income statement from these price floors when they settle during the third and fourth quarters of 2008 would be $4.3 million, which represents the original amount paid for these price floors less ineffectiveness previously recognized.

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 the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At June 30, 2008, we had borrowings of $124.2 million under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 50 basis points and would not have a material adverse effect on our 2008 cash flows based on this same 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 first six months of 2008 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 2007 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 first six months of 2008:

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)
01/01/08 – 01/31/08 (1)	781	$42.93	---	$---
02/01/08 – 02/29/08 (1)	32,649	40.79	---	---
03/01/08 – 03/31/08 (1)	464	45.97	---	---
Total	33,894	$40.91	---	$---

(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.

Our annual meeting of shareholders was held on May 13, 2008. At the record date, 30,477,314 shares of common stock were outstanding and entitled to one vote per share upon all matters submitted at the meeting. At the annual meeting, Deanna L. Cannon, Douglas J. Lanier and Bruce H. Vincent were elected to serve as directors of Swift Energy for three-year terms to expire at the 2011 annual meeting of shareholders. These directors were elected by the following votes:

Nominees for Director	For	Withheld
Deanna L. Cannon	14,437,406	391,145
Douglas J. Lanier	14,425,034	403,517
Bruce H. Vincent	14,161,823	666,728

The following proposals were also approved at the annual meeting:

Proposal	For	Against	Abstain	Broker Non-Vote
Proposal to amend the Company's 2005 Stock Compensation Plan	9,488,798	2,480,332	13,061	2,846,360
Proposal to amend the Company's Employee Stock Purchase Plan	11,885,652	80,458	16,081	2,846,380
Company's Independent Auditors for the fiscal year ending December 31, 2008	14,596,775	220,536	11,240	0

Item 5. Other Information.

None.

Item 6. Exhibits.

10.1*	Fourth Amendment to First Amended and Restated Credit Agreement effective as of May 1, 2008, by and among Swift Energy Company and Swift Energy Operating, LLC, and, J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent.
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: August 7, 2008	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: August 7, 2008	By:	/s/ David W. Wesson. David W. Wesson Controller and Principal Accounting Officer

Exhibit Index

10.1*	Fourth Amendment to First Amended and Restated Credit Agreement effective as of May 1, 2008, by and among Swift Energy Company and Swift Energy Operating, LLC, and, J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent.
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