SWIFT ENERGY CO
Form 10-Q
November 06, 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 September 30, 2008
Commission File Number 1-8754

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

Texas	20-3940661
(State of Incorporation)	(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, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	þ	Accelerated filer	o	Non-accelerated filer	o	Smaller Reporting Company	o

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

Yes o No þ

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

Common Stock	
($.01 Par Value)	30,855,150 Shares
(Class of Stock)	(Outstanding at October 31, 2008)

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2008

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First Amended and Restated 2005 Stock Compensation Plan dated November 4, 2008.

Swift Energy Company Change of Control Severance Plan dated November 4, 2008.

Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Terry E. Swift dated November 4, 2008.

Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Bruce H. Vincent dated November 4, 2008.

Second Amended and Restated Executed Employment Agreement between Swift Energy Company and Alton D. Heckaman dated November 4, 2008.
Executive Employment Agreement between Swift Energy Company and Robert J. Banks dated November 4, 2008.
Amended and Restated Executive Employment Agreement between Swift Energy Company and James P. Mitchell dated November 4, 2008.
Second Amended and Restated Executive Employment Agreement between Swift Energy Company and James M. Kitterman dated November 4, 2008.
Certification of CEO Pursuant to rule 13a-14(a)
Certification of CFO Pursuant to rule 13a-14(a)
Certification of CEO & CFO Pursuant to Section 1350

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

	September 30, 2008 (Unaudited)	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,801	$ 5,623
Accounts receivable-		
Oil and gas sales	41,779	72,916
Joint interest owners	775	1,587
Other Receivables	7,848	1,324
Deferred tax asset	---	8,055
Other current assets	28,320	13,896
Current assets held for sale	564	96,549
Total Current Assets	88,087	199,950
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	3,113,205	2,610,469
Unproved properties	108,373	106,643
	3,221,578	2,717,112
Furniture, fixtures, and other equipment	36,289	33,064
	3,257,867	2,750,176
Less – Accumulated depreciation, depletion, and amortization	(1,153,377)	(989,981)
	2,104,490	1,760,195
Other Assets:		
Debt issuance costs	6,399	7,252
Restricted assets	1,834	1,654
	8,233	8,906
	$ 2,200,810	$ 1,969,051
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 84,143	$ 89,281
Accrued capital costs	91,650	94,947
Accrued interest	8,754	7,558
Undistributed oil and gas revenues	4,124	10,309
Current liabilities associated with assets held for sale	---	8,066
Total Current Liabilities	188,671	210,161
Long-Term Debt	516,600	587,000
Deferred Income Taxes	405,177	302,303
Asset Retirement Obligation	33,702	31,066
Other Long-Term Liabilities	2,288	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, 31,312,242 and 30,615,010 shares issued, and 30,850,999 and 30,178,596 shares outstanding, respectively	313	306
Additional paid-in capital	431,151	407,464
Treasury stock held, at cost, 461,243 and 436,414 shares, respectively	(10,156)	(7,480)
Retained earnings	628,381	436,178
Accumulated other comprehensive income (loss), net of income tax	4,683	(414)
	1,054,372	836,054
	$ 2,200,810	$ 1,969,051

See accompanying Notes to Consolidated Financial Statements.

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

	Three Months Ended		Nine Months Ended	
	09/30/08	09/30/07	09/30/08	09/30/07
Revenues:				
Oil and gas sales	$ 214,113	$ 170,001	$ 677,270	$ 456,534
Price-risk management and other, net	(346)	1,271	(1,862)	1,227
	213,767	171,272	675,408	457,761
Costs and Expenses:				
General and administrative, net	10,113	8,294	30,323	25,503
Depreciation, depletion, and amortization	52,217	48,431	161,991	134,007
Accretion of asset retirement obligation	511	341	1,432	1,031
Lease operating cost	24,966	17,896	79,975	49,788
Severance and other taxes	20,146	19,531	69,138	53,372
Interest expense, net	6,935	5,700	23,856	19,742
Debt retirement cost	---	---	---	12,765
	114,888	100,193	366,715	296,208
Income from Continuing Operations Before Income Taxes	98,879	71,079	308,693	161,553
Provision for Income Taxes	36,608	28,164	113,342	61,670
Income from Continuing Operations	62,271	42,915	195,351	99,883
Income (Loss) from Discontinued Operations, net of taxes	(348)	(633)	(3,148)	1,497
Net Income	$ 61,923	$ 42,282	$ 192,203	$ 101,380
Per Share Amounts-				
Basic: Income from Continuing Operations	$ 2.02	$ 1.43	$ 6.38	$ 3.34
Income (Loss) from Discontinued Operations, net of taxes	(0.01)	(0.02)	(0.10)	0.05
Net Income	$ 2.01	1.41	$ 6.28	$ 3.39
	$ 1.98	$ 1.40	$ 6.26	$ 3.27

Diluted: Income from Continuing Operations				
Income (Loss) from Discontinued Operations, net of taxes	(0.01)	(0.02)	(0.10)	0.05
Net Income	$ 1.97	$ 1.38	$ 6.16	$ 3.32
Weighted Average Shares Outstanding	30,830	30,051	30,595	29,937

See accompanying Notes to Consolidated Financial Statements.

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

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	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 (410,416 shares) (2)	4	8,238	-	-	-	8,242
Purchase of treasury shares (63,981 shares) (2)	-	-	(3,347)	-	-	(3,347)
Excess tax benefits from stock-based awards (2)	-	1,502	-	-	-	1,502
Employee stock purchase plan (25,645 shares) (2)	-	944	-	-	-	944
Issuance of restricted stock (261,171 shares) (2)	3	(3)	-	-	-	-
Amortization of stock compensation (2)	-	11,988	-	-	-	11,988
Comprehensive income:						
Net income (2)	-	-	-	192,203	-	192,203
Other comprehensive income (2)	-	-	-	-	5,097	5,097

Total comprehensive income (2)						197,300
Balance, September 30, 2008 (2)	$ 313	$ 431,151	$ (10,156)	$ 628,381	$ 4,683	$ 1,054,372

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

See accompanying Notes to Consolidated Financial Statements.

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

(in thousands)	Nine Months Ended September 30, 2008	2007
Cash Flows from Operating Activities:		
Net income	$ 192,203	$ 101,380
Plus (income) loss from discontinued operations, net of taxes	3,148	(1,497)
Adjustments to reconcile net income to net cash provided by operation activities -		
Depreciation, depletion, and amortization	161,991	134,007
Accretion of asset retirement obligation	1,432	1,031
Deferred income taxes	104,837	61,547
Stock-based compensation expense	8,613	7,783
Debt retirement costs – cash and non-cash	---	12,765
Other	2,381	298
Change in assets and liabilities-		
Decrease in accounts receivable	25,217	4,333
Increase (decrease) in accounts payable and accrued liabilities	(1,614)	1,644
Decrease in income taxes payable	(79)	(884)
Increase (decrease) in accrued interest	1,196	(187)
Cash Provided by operating activities – continuing operations	499,325	322,220
Cash Provided by operating activities – discontinued operations	5,815	18,099
Net Cash Provided by Operating Activities	505,140	340,319
Cash Flows from Investing Activities:		
Additions to property and equipment	(473,286)	(326,803)
Proceeds from the sale of property and equipment	124	219
Acquisitions of oil and gas properties	(46,472)	---
Net cash received as operator of partnerships and joint ventures	---	485
Cash Used in investing activities – continuing operations	(519,634)	(326,099)
Cash Provided by (Used in) investing activities – discontinued operations	80,731	(9,095)
Net Cash Used in Investing Activities	(438,903)	(335,194)
Cash Flows from Financing Activities:		
Proceeds from long-term debt	---	250,000
Payments of long-term debt	---	(200,000)
Net payments from bank borrowings	(70,400)	(31,400)
Net proceeds from issuances of common stock	9,186	2,521
Excess tax benefits from stock-based awards	1,502	---
Purchase of treasury shares	(3,347)	(1,766)
Payments of debt retirement costs	---	(9,376)

Payments of debt issuance costs		---		(4,451)
Cash Provided by (Used in) financing activities – continuing operations		(63,059)		5,528
Cash Provided by financing activities – discontinued operations		---		---
Net Cash Provided by (Used in) financing activities		(63,059)		5,528
Net Increase in Cash and Cash Equivalents	$	3,178	$	10,653
Cash and Cash Equivalents at Beginning of Period		5,623		1,058
Cash and Cash Equivalents at End of Period	$	8,801	$	11,711
Supplemental Disclosures of Cash Flows Information:				
Cash paid during period for interest, net of amounts capitalized	$	21,810	$	19,008
Cash paid during period for income taxes	$	8,505	$	1,007

See accompanying Notes to Consolidated Financial Statements.

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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.

Commitments and Contingencies. We have been named as a defendant in a number of lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

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 related to the collectibility of accounts receivable and the credit worthiness of our customers,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,

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- estimates of insurance recoveries related to property damage,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

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

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 nine months ended September 30, 2008 and 2007, such internal costs capitalized totaled $22.8 million and $19.6 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the nine months ended September 30, 2008 and 2007, capitalized interest on unproved properties totaled $6.0 million and $7.2 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. 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 September 30, 2008 consisted of oil floors with strike prices below the period-end price and natural gas price floors with strike prices above the period-end price and did not materially affect this calculation.

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 continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and 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 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 September 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 collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At September 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 a 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. We do not utilize these derivative instruments for trading and only enter into derivative agreements with banks in our credit facility. During the third quarters of 2008 and 2007, we recognized net losses of $0.8 million and net gains of $1.0 million, respectively, relating to our derivative activities. During the first nine months of 2008 and 2007, we recognized a net loss of $2.7 million and a net gain of $0.3 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 September 30, 2008, the Company had recorded $4.7 million, net of taxes of $2.7 million, of derivative gains 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 nine months of 2008 and 2007 was not material. All amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" will be realized within the next three months when the forecasted sales of hedged production occurs.

At September 30, 2008, we had in place oil and natural gas price floors in effect for the contract months of October 2008 through December 2008 that cover a portion of our oil and natural gas production for October 2008 to December 2008. The oil price floors cover notional volumes of 630,000 barrels, with a weighted average floor price of $98.15 per barrel. Our oil price floors in place at September 30, 2008 are expected to cover approximately 45% to 50% of our estimated oil production from October 2008 to December 2008. The natural gas price floors cover notional volumes of 2,700,000 MMBtu, with a weighted average floor price of $9.15 per MMBtu. Our natural gas price floors in place at September 30, 2008 are expected to cover approximately 50% to 55% of our estimated natural gas production from October 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 income (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 income (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 September 30, 2008, was $9.4 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 nine 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 $11.5 million and $8.0 million in the first nine 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 $12.1 million at September 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 September 30, 2008 and 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of September 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 income tax returns from 1998 through 2003 and 2005 forward, our 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 both September 30, 2008 and December 31, 2007 are liabilities of approximately $12.6 million 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 Income (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 September 30, 2008, we recorded $4.7 million, net of taxes of $2.7 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive income and related tax effects for 2008 were as follows (in thousands):

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	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	5,431	(2,004)	3,427
Effect of cash flow hedges settled during the period	2,647	(977)	1,670
Other comprehensive income at September 30, 2008	$ 7,420	$ (2,737)	$ 4,683

Total comprehensive income was $68.6 million and $42.1 million for the third quarters of 2008 and 2007, respectively. Total comprehensive income was $197.3 million and $101.1 million for the nine 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 expected date of abandonment. 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 nine months ended September 30	1,432	1,030
Liabilities incurred for new wells and facilities construction	1,349	321
Liabilities incurred for acquisitions	162	---
Reductions due to sold, or plugged and abandoned wells	(107)	---
Revisions in estimated cash flows	824	---
Asset Retirement Obligation as of September 30	$ 38,119	$ 30,145

At September 30, 2008 and December 31, 2007, approximately $4.4 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 February 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.

(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 $4.3 million and $1.0 million for the nine months ended September 30, 2008 and 2007, respectively. The benefit for the first nine 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 $2.8 million, and the benefit for the first nine 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 $1.0 million.

Net cash proceeds from the exercise of stock options were $8.2 million and $1.9 million for the nine months ended September 30, 2008 and 2007. The actual income tax benefit realized from stock option exercises was $3.9 million and $1.2 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 $2.4 million and $2.3 million for the quarters ended September 30, 2008 and 2007, respectively, and was $7.9 million and $6.7 million for the nine month periods ended September 30, 2008 and 2007. Stock compensation recorded in lease operating cost was $0.1 million for each of the quarters ended September 30, 2008 and 2007, and was $0.5 million and $0.4 million for each of the nine month periods ended September 30, 2008 and 2007, respectively. We also capitalized $1.1 million of stock compensation in each of the third quarters of 2008 and 2007, and capitalized $3.4 million and $3.2 million of stock compensation in the nine month periods ended September 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 September 30,		Nine month Ended September 30,	
	2008	2007	2008	2007
Dividend yield	---	0%	0%	0%
Expected volatility	---	37.5%	38.9%	38.5%
Risk-free interest rate	---	4.0%	2.5%	4.8%
Expected life of options (in years)	---	4.3	4.2	6.2
Weighted-average grant-date fair value	---	$ 14.83	$ 15.53	$ 20.05

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 September 30, 2008, we had $2.9 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.3 years. The following table represents stock option activity for the nine months ended September 30, 2008:

	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,449,240	$ 28.47
Options granted	210,317	$ 47.18
Options canceled	(23,668)	$ 27.78
Options exercised	(485,494)	$ 20.06
Options outstanding, end of period	1,150,395	$ 33.12
Options exercisable, end of period	557,503	$ 27.66

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at September 30, 2008 was $37.9 million and 5.3 years and $22.2 million and 3.8 years, respectively. Total intrinsic value of options exercised during the nine months ended September 30, 2008 was $13.6 million.

Restricted Stock

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 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 September 30, 2008, we had unrecognized compensation expense of approximately $14.3 million associated with these awards which are expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested during the nine months ended September 30, 2008 was $10.9 million.

The following table represents restricted stock activity for the nine months ended September 30, 2008:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	596,590	$ 41.60
Restricted shares granted	300,790	$ 44.27
Restricted shares canceled	(45,191)	$ 42.60
Restricted shares vested	(264,609)	$ 41.17
Restricted shares outstanding, end of period	587,580	$ 43.08

(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 September 30, 2008 and 2007, and are discussed below.

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

	Three Months Ended September 30, 2008			Three Months Ended September 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	$ 62,271	30,830	$ 2.02	$ 42,915	30,051	$ 1.43
Dilutive Securities:						
Restricted Stock	--	267		--	158	
Stock Options	--	330		--	477	
Diluted EPS:						
Net Income from continuing operations, and assumed Share conversions	$ 62,271	31,427	$ 1.98	$ 42,915	30,686	$ 1.40

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	Nine months ended September 30, 2008			Nine months ended September 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	$ 195,351	30,595	$ 6.38	$ 99,883	29,937	$ 3.34
Dilutive Securities:						
Restricted Stock	--	270		--	161	
Stock Options	--	341		--	484	
Diluted EPS:						
Net Income from continuing operations, and assumed Share conversions	$ 195,351	31,206	$ 6.26	$ 99,883	30,582	$ 3.27

Options to purchase approximately 1.2 million shares at an average exercise price of $33.12 were outstanding at September 30, 2008, while options to purchase 1.6 million shares at an average exercise price of $27.84 were outstanding at September 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 both the three months ended September 30, 2008 and 2007, and 0.8 million and 1.1 million options to purchase shares were not included in the computation of Diluted EPS for both the nine months ended September 30, 2008 and 2007, 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 0.3 million and 0.4 million shares were not included in the computation of Diluted EPS for both the three months ended September 30, 2008 and 2007, and 0.3 million and 0.4 million were not included in the computation of Diluted EPS for both the nine months ended September 30, 2008 and 2007, 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 September 30, 2008 and December 31, 2007, was as follows (in thousands):

	September 30, 2008	December 31, 2007
Bank Borrowings	$ 116,600	$ 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	$ 516,600	$ 587,000

Bank Borrowings. At September 30, 2008, we had borrowings of $116.6 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 September 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. In October 2008, our lenders reaffirmed our borrowing base and commitment amount as part of their normal recurring borrowing base review. 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 May 2009.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million and $0.4 million for the three months ended September 30, 2008 and 2007, respectively, and $6.9 million and $3.0 million for the nine months ended September 30, 2008 and 2007, respectively. The amount of commitment fees included in interest expense, net was $0.1 million and $0.2 million for the three month periods ended September 30, 2008 and 2007, respectively, and $0.3 million and $0.4 million for the nine month periods ended September 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. 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 September 30, 2008 and 2007, respectively, and $9.0 million for each of the nine month periods ended September 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 $8.9 million for the nine month period ended September 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 for each of the three month periods ended September 30, 2008 and 2007, and $13.6 million and $6.0 million for the nine month periods ended September 30, 2008 and 2007, respectively.

The maturities on our long-term debt are $0 for 2008, 2009 and 2010, $266.6 million for 2011, and $250 million thereafter.

We have capitalized interest on our unproved properties in the amount of $2.1 million and $2.2 million for the three months ended September 30, 2008 and 2007, respectively, and $6.0 million and $7.2 million for the nine month periods ended September 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 August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. In connection with the sale of our last permit, a third-party has brought suit against Swift Energy for breach of contract related to obtaining their consent for the transfer of the permit. The third-party has also brought suit against the New Zealand Ministry of Economic Development which challenges the transfer of this permit from Swift Energy to the purchaser. We have evaluated the situation and believe we have not met the revenue recognition criteria at this time for the permit sale, and have deferred the potential gain on this property sale pending the outcome of this litigation.

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 sheets. During the fourth quarter of 2007 and the first nine months 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 $3.6 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 September 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 September 30, 2008	Three Months Ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Oil and gas sales	$ ---	$ 9,524	$ 14,675	$ 31,694
Other revenues	(17)	320	764	1,027
Total revenues	(17)	9,844	15,439	32,721
Depreciation, depletion, and amortization	(52)	5,137	4,857	16,887
Other operating expenses	314	6,169	10,450	16,196
Non-cash write-down of property and equipment	285	---	3,581	---
Total expenses	547	11,306	18,888	33,083
Loss from discontinued operations before income taxes	(564)	(1,462)	(3,449)	(362)
Income tax benefit	(216)	(829)	(301)	(1,859)
Loss from discontinued operations, net of taxes	$ (348)	$ (633)	$ (3,148)	$ 1,497
Loss per common share from discontinued operations-diluted	$ (0.01)	$ (0.02)	$ (0.10)	$ 0.05
Sales volumes (MBoe)	---	324	415	1,079
Cash flow provided by (used in) operating activities	$ (875)	$ 5,427	$ 5,815	$ 18,099
Capital expenditures	---	$ 1,559	$ 2,013	$ 9,095

Total New Zealand assets were $10.6 million at September 30, 2008 and $110.6 million at December 31, 2007. Our capitalized general and administrative expenses were immaterial in the 2008 period and totaled $1.0 million and $3.4 million for the three months and nine months ended September 30, 2007, respectively.

As of September 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 August 2008, we announced the acquisition of oil and natural gas interests in South Texas from Crimson Energy Partners, L.P. a privately held company. The property interests are located in the Briscoe "A" lease in Dimmit County. We paid approximately $46.5 million in cash for these interests including purchase price adjustments. After taking into account internal acquisition costs of $1.4 million, our total cost was $47.9 million. We allocated $44.5

million of the acquisition price to “Proved Properties,” $3.4 million to “Unproved Properties,” and recorded a liability for $0.2 million to “Asset retirement obligation” on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South 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 and are not material to our year-to-date 2008 results.

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) Fair Value Measurements

We adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements," on January 1, 2008. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosure about 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. The adoption of this statement did not have a material impact on our financial position or results of operations.

The following tables present our assets that are measured at fair value on a recurring basis during the nine months ended September 30, 2008 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value.

(in Millions)	Fair Value Measurements at September 30, 2008			
Assets	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Hedging contracts	$ 9.4	$ ---	$ ---	$ 9.4

The table below presents a reconciliation for assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the three months ended September 30, 2008 (in millions):

Fair Value Reconciliation at September 30, 2008 – three months QTD	Hedging Contracts
Balance as of June 30, 2008	$ 1.1
Total gains/(losses) (realized or unrealized):	
Included in earnings	(0.8)
Included in other comprehensive income	10.6
Purchases, issuances and settlements	(1.5)
Transfers in and out of Level 3	---
Balance as of September 30, 2008	$ 9.4

The approximate amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to derivatives still held at September 30, 2008	$	0.1

The table below presents a reconciliation for assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the nine months ended September 30, 2008 (in Millions):

Fair Value Reconciliation at September 30, 2008 – nine months YTD	Hedging Contracts
Balance as of January 1, 2008	$ 0.3
Total gains/(losses) (realized or unrealized):	
Included in earnings	(2.7)
Included in other comprehensive income	8.1
Purchases, issuances and settlements	3.7
Transfers in and out of Level 3	---
Balance as of September 30, 2008	$ 9.4
The approximate amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to derivatives still held at September 30, 2008	$ 0.1

(9) 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)	September 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	$ ---	$ 78,789	$ 9,298	$ ---	88,087
Property and equipment	---	2,104,309	181	---	2,104,490
Investment in subsidiaries (equity method)	1,054,372	---	981,625	(2,035,997)	---
Other assets	---	8,233	62,928	(62,928)	8,233
Total assets	$ 1,054,372	$ 2,191,331	$ 1,054,032	$ (2,098,925)	$ 2,200,810

LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 188,710	$ (39)	$ ---	$ 188,671
Long-term liabilities	---	1,020,996	(301)	(62,928)	957,767
Stockholders' equity	1,054,372	981,625	1,054,372	(2,035,997)	1,054,372
Total liabilities and stockholders' equity	$ 1,054,372	$ 2,191,331	$ 1,054,032	$ (2,098,925)	$ 2,200,810

(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 September 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 213,767	$ ---	$ ---	$ 213,767
Expenses	---	114,888	---	---	114,888
Income before the following:	---	98,879	---	---	98,879
Equity in net earnings of subsidiaries	61,923	---	62,271	(124,194)	---
	61,923	98,879	62,271	(124,194)	98,879

Income from continuing operations, before income taxes					
Income tax provision	---	36,608	---	---	36,608
Income from continuing operations	61,923	62,271	62,271	(124,194)	62,271
Loss from discontinued operations, net of taxes	---	---	(348)	---	(348)
Net income	$ 61,923	$ 62,271	$ 61,923	$ (124,194)	$ 61,923

(in thousands)	Nine months ended September 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 675,408	$ ---	$ ---	$ 675,408
Expenses	---	366,715	---	---	366,715
Income before the following:	---	308,693	---	---	308,693
Equity in net earnings of subsidiaries	192,203	---	195,351	(387,554)	---
Income from continuing operations, before income taxes	192,203	308,693	195,351	(387,554)	308,693
Income tax provision	---	113,342	---	---	113,342
Income from continuing operations	192,203	195,351	195,351	(387,554)	195,351
Loss from discontinued operations, net of taxes	---	---	(3,148)	---	(3,148)
Net income	$ 192,203	$ 195,351	$ 192,203	$ (387,554)	$ 192,203

(in thousands)	Three Months Ended September 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 171,272	$ ---	$ ---	$ 171,272
Expenses	---	100,193	---	---	100,193
Income before the following:	---	71,079	---	---	71,079
Equity in net earnings of subsidiaries	42,282	---	42,915	(85,197)	---
Income from continuing operations, before income taxes	42,282	71,079	42,915	(85,197)	71,079
Income tax provision	---	28,164	---	---	28,164
Income from continuing operations	42,282	42,915	42,915	(85,197)	42,915
Income from discontinued operations, net of taxes	---	---	(633)	---	(633)
Net income	$ 42,282	$ 42,915	$ 42,282	$ (85,197)	$ 42,282

(in thousands)	Nine months ended September 30, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 457,761	$ ---	$ ---	$ 457,761
Expenses	---	296,208	---	---	296,208
Income before the following:	---	161,553	---	---	161,553
Equity in net earnings of subsidiaries	101,380	---	99,883	(201,263)	---
Income from continuing operations,	101,380	161,553	99,883	(201,263)	161,553

before income taxes					
Income tax provision	---	61,670	---	---	61,670
Income from continuing operations	101,380	99,883	99,883	(201,263)	99,883
Income from discontinued operations, net of taxes	---	---	1,497	---	1,497
Net income	$ 101,380	$ 99,883	$ 101,380	$ (201,263)	$ 101,380

Condensed Consolidating Statements of Cash Flow

(in thousands)	Nine months ended September 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	$ ---	$ 499,325	$ 5,815	$ ---	$ 505,140
Cash flow from investing activities	---	(436,379)	80,731	(83,255)	(438,903)
Cash flow from financing activities	---	(63,059)	(83,255)	83,255	(63,059)
Net increase in cash	---	(113)	3,291	---	3,178
Cash, beginning of period	---	180	5,443	---	5,623
Cash, end of period	$ ---	$ 67	$ 8,734	$ ---	$ 8,801

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

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 39 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 crude oil in the state of Louisiana, and due to our South Louisiana operations, oil constitutes 51% of our third quarter 2008 production, and together with our natural gas liquids ("NGLs") production, comprising 63% of our third quarter 2008 production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in recent periods.

Financial Condition

Recent extreme volatility in worldwide credit and financial markets, combined with rapidly falling prices for oil and natural gas, all of which began in the third quarter of 2008, is likely to have a significant impact on our cash flow, capital expenditures, and liquidity in future periods. Oil and natural gas prices began to decline late in the third quarter, but only led to a 5% decline in average prices per BOE received when compared to average prices in the second quarter of 2008. Oil and natural gas prices declined significantly during October 2008, which will reduce our cash flow from operations in the fourth quarter and in future periods in which prices remain at these lower levels. The oil and natural gas price floors that cover a portion of our fourth quarter 2008 production will become more valuable if prices continue to decline in that quarter.

The Company has reduced its capital expenditure budget for the remainder of 2008 in part by releasing several drilling rigs in South Louisiana, and anticipates lower capital expenditures in 2009 than in 2008. A large factor in setting our 2009 capital expenditures budget is the degree to which commodity prices stabilize prior to the beginning of 2009. Because our exploration and development activities are to a degree scalable, we anticipate being able to adjust our capital expenditures to the level of cash flow from operations, supplemented with funds available under our credit facility.

In light of recent credit market volatility, many financial institutions have liquidity issues, and governments have intervened in these markets to create liquidity. We have reviewed the creditworthiness of the banks that fund our credit facility and thus far our liquidity has not been impacted. However, if the current credit market volatility is prolonged; future extensions of our credit facility may contain terms and interest rates not as favorable as those of our current credit facility. At October 31, 2008, we had drawn $152.9 million under our credit facility which expires in October 2011, under which we have a current borrowing base of $400 million, which was reaffirmed effective November 1, 2008 as part of the normal recurring semi-annual re-determination of our borrowing base. Our available borrowings under our line of credit facility provide us liquidity.

Our debt to capitalization ratio decreased to 33% at September 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 13% at September 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.

Operating Results

In the third quarter of 2008 we had strong income and cash flows. Income from continuing operations increased 45% to $62.3 million and cash flows from operating activities from continuing operations increased 59% to $204.6 million, in each case compared to the third quarter of 2007. Production from our continuing operations decreased 14% to 2.32 MMBoe as a result of production shut-ins necessitated by Hurricanes Gustav and then Ike. We estimate the effect of these hurricanes deferred approximately 0.5 MMBoe of production from the third quarter of 2008. The effects of the hurricane will also be felt into the fourth quarter as the drilling and completion of several wells was delayed as we moved drilling rigs into safe harbor before the hurricanes and then returned them to the field afterwards. We also had strong quarterly revenues of $213.8 million for the third quarter of 2008, an increase of 25% over comparable 2007 levels. Our weighted average sales price received increased 47% to $92.34 per Boe for the third quarter of 2008 from $62.92 received during the third quarter of 2007. Our $44.1 million, or 26%, increase in oil and gas sales revenues resulted from 61% higher oil prices, 44% higher NGL prices, and 71% higher natural gas prices during the 2008 period.

Hurricane Gustav shut-down procedures were implemented beginning August 28, 2008 in our Lake Washington region and South Lafayette region. Although Hurricane Gustav caused damage to our Lake Washington field and South Lafayette region, the Bay de Chene field experienced significant damage to its production facilities, and some production equipment in the field was damaged or destroyed. Hurricane Ike made landfall on September 13, 2008, and caused damage to several fields in our South Lafayette region and our High Island field due to high water levels. As a result of these hurricanes, approximately 0.5 MMBoe of production was shut-in during the third quarter of 2008, and approximately 0.3 MMBoe of production is estimated to remain shut-in for the fourth quarter of 2008. By October 1, 2008, production in our Lake Washington field had returned to 85% of pre-storm levels and all operated production had been restored in our South Lafayette region. We anticipate that some production in our Bay de Chene field may resume this year, but pre-storm production levels are not expected to be reached again until mid-year of 2009. We anticipate our total cost for the replacement of assets, repairs, and clean-up costs related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will approximate $20 million and we believe a portion of this will be reimbursed by insurance coverage. During the third quarter of 2008, we recorded approximately $2.2 million of costs related to the hurricanes; $2.0 million related to clean-up and repair costs was expensed to lease operating expense while $0.2 million related to capital projects was capitalized to the full cost pool. We expect the remainder of these costs will be incurred in the fourth quarter of 2008 and the first two quarters of 2009 and mainly relate to capital projects.

During the third quarter of 2008, our overall costs and expenses increased 15% when compared to those costs in the same 2007 period. The largest increase in these costs and expenses was attributable to a 40% increase in lease operating expense due to a higher well count mainly from our South Texas property acquisition in late 2007, increasing costs for industry goods and services, higher NGL and natural gas processing costs, and clean-up and repair activities related to Hurricanes Gustav and Ike. Depreciation, depletion and amortization expense increased 8%, mainly due to our larger depletable property base. Severance and other taxes also increased 3% mainly due to increased oil and gas revenues. We expect the market forces that were putting upward pressure on production costs for the first three quarters of 2008 to soften as activity levels decline in response to falling commodity prices and current conditions in the financial markets. However, we do not expect the full impact of these cost reductions to be realized until the first quarter of 2009.

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Lake Washington is our most significant field, and provided approximately 40% of our production in the third quarter of 2008. In the third quarter of 2008, after taking into account shut-in production related to the hurricanes, production in the Lake Washington field was flat when compared to second quarter 2008 levels, and approximately 25% lower than production levels in last year's third quarter. The field has experienced natural declines and reservoir pressure issues for some time and was also affected by hurricane activity and shut-in for a portion of September 2008 as noted above. Production at Lake Washington was restored to approximate pre-storm levels by October 1. Permits were submitted to the State of Louisiana to provide additional water injection into the Newport reservoir for pressure maintenance. However, based on our recent experiences, we do not anticipate that pressure maintenance activities will significantly increase our production in Lake Washington until the later half of 2009. Water injection into the current injection well is averaging about 1,200-1,300 barrels per day. A second 6" diameter production line was installed between the Newport header and Westside facility during the quarter. This line successfully reduced back pressure on the wells at the Newport header and resulted in a production increase of about 600 BOPD. The positive impact of this line on the production for 3Q08 was over shadowed by the negative impact of the two hurricanes.

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.

Asset Acquisitions and Dispositions

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 August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. In connection with the sale of our last permit, a third-party has brought suit against Swift for breach of contract related to obtaining their consent for the transfer of the permit. The third-party has also brought suit against the New Zealand Ministry of Economic Development which challenges the transfer of this permit from Swift Energy to the purchaser. We have evaluated the situation and believe we have not met the revenue recognition criteria at this time for the property sale, and have deferred the potential gain on this permit sale pending the outcome of this litigation. 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.

In August 2008, we acquired oil and natural gas interests in South Texas for approximately $46.5 million in cash including purchase price adjustments. The property interests are located in the Briscoe "A" lease in Dimmit County. These properties are now included in our Cotulla area within our South Texas region.

Capital Expenditures

Our capital expenditures related to continuing operations during the first nine months of 2008 of $519.6 million, which includes $46.5 million in acquisitions. This amount increased by $193.5 million 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 and the acquisition of additional properties in the Cotulla area of South Texas during the third quarter of 2008. These expenditures were funded by $499.3 million of cash provided by operating activities from continuing operations and proceeds from our New Zealand asset sale.

Our current 2008 capital expenditure budget is $585 million to $610 million, net of minor non-core dispositions and excluding any property acquisitions. Based upon current market conditions, commodity prices, and our estimates, our capital expenditures for 2008 are likely to be greater than our anticipated cash flow from operations. We currently have budgeted approximately two-thirds of these amounts for our South Louisiana regions, and on an overall basis three-fourths for developmental activities. For the full year 2008, after taking into account approximately 0.8 MMBOE of estimated shut-in production related to the hurricanes, we are targeting production from our continuing operations to increase 2% to 3% and proved reserves to increase 3% to 4% both over 2007 levels.

Also in the Lake Washington and Bay de Chene area during 2008, we are working on our 3D seismic depth migration of the merged data sets with an updated "salt model." We also completed a pilot 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 conducting completion operations on our Shasta prospect and currently drilling one of our West Newport prospects. A full inventory of deep and higher impact tests have been developed for future 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, which could be drilled next year dependant upon the commodity pricing environment.

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

Revenues. Our revenues in the third quarter of 2008 increased by 25% compared to revenues in the same period in 2007, due to higher commodity prices which were partially offset by lower production. Revenues for both periods were substantially comprised of oil and gas sales. Crude oil production was 51% of our production volumes in the third quarter of 2008 and 66% of our production in the third quarter of 2007. Natural gas production was 37% of our production volumes in the third quarter of 2008 and 27% in the third quarter of 2007.

Our 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 September 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	$ 124.0	$ 129.2	1,151	1,868
North Lafayette	25.6	13.6	262	254
South Lafayette	15.0	12.1	179	233
South Texas	47.0	12.7	693	299
Other	2.5	2.4	34	48
Total	$ 214.1	$ 170.0	2,319	2,702

Our third quarter of 2008 production was adversely affected by Hurricanes Gustav and Ike. As a result of these hurricanes, approximately 0.5 MBoe of production was shut-in during the third quarter of 2008 predominantly in South Louisiana.

Oil and gas sales for the third quarter of 2008 increased by 26%, or $44.1 million, from the level of those revenues for the comparable 2007 period, while our net sales volumes in the third quarter of 2008 decreased by 14%, or 0.4 MMBoe, from net sales volumes in the third quarter of 2007. Average prices for oil increased to $122.71 per Bbl in the third quarter of 2008 from $76.20 per Bbl in the third quarter of 2007. Average natural gas prices increased to $9.70 per Mcf in the third quarter of 2008 from $5.68 per Mcf in the third quarter of 2007. Average NGL prices increased to $70.55 per Bbl in the third quarter of 2008 from $48.89 per Bbl in the third quarter of 2007.

In the third quarter of 2008, our $44.1 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $81.4 million favorable impact on sales, of which $54.5 million was attributable to the 61% increase in average oil prices received, $6.4 million was attributable to the 44% increase in NGL prices, and $20.5 million was attributable to the 71% increase in natural gas prices; offset by

- Volume variances that had a $37.3 million unfavorable impact on sales, with $46.6 million of decreases attributable to the 0.6 million Bbl decrease in oil sales volumes, offset by a $5.1 million increase due to the 0.1 million Bbl increase in NGL sales volumes, and a $4.2 million increase due to the 0.7 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 September 30, 2008	1,171	294	5.1	2,319	$ 122.71	$ 70.55	$ 9.70
Three Months Ended September 30, 2007	1,783	190	4.4	2,702	$ 76.20	$ 48.89	$ 5.68

During the third quarter of 2008, we recognized a net loss of $0.8 million and during the third quarter of 2007 we recognized a net gain of $1.0 million, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. Had the loss and gain been recognized in the oil and gas sales account, our average oil sales price would have been $121.42 and $76.20 for the third quarters of 2008 and 2007, respectively, and our average natural gas sales price would have been $9.83 and $5.91 for the third quarters of 2008 and 2007, respectively.

Costs and Expenses. Our expenses in the third quarter of 2008 increased $14.7 million, or 15%, compared to expenses in the same period of 2007.

Our third quarter 2008 general and administrative expenses, net, increased $1.8 million, or 22%, 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 third quarters of 2008 and 2007, our capitalized general and administrative costs totaled $8.1 million and $6.6 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.36 per Boe in the third quarter of 2008 from $3.07 per Boe in the third quarter of 2007. The portion of supervision fees recorded as a reduction to general and administrative expenses was $3.7 million and $2.7 million for three month periods ended September 30, 2008 and 2007, respectively.

DD&A increased $3.8 million, or 8%, in the third quarter of 2008, from levels in the third quarter of 2007. The increase is due to increases in the depletable oil and natural gas property base, partially offset by increases in reserves from prior year levels and lower production in the 2008 period. Industry costs for services and goods have increased over the last three year period and have contributed to the increase in the full cost pool and resulting DD&A expense. Our DD&A rate per Boe of production was $22.52 and $17.93 in the third 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 third quarters of 2008 and 2007, respectively.

Our lease operating costs increased $7.1 million, or 40%, over the level of such expenses in the same 2007 period. Lease operating costs increased during 2008 due to additional costs from the Cotulla properties acquired in the fourth quarter of 2007, increasing costs for industry goods and services, higher natural gas and NGL processing costs, and approximately $2.0 million of costs related to clean-up and repair activities related to hurricanes Gustav and Ike in the third quarter of 2008. Our lease operating costs per Boe produced were $10.77 and $6.62 in the third quarters of 2008 and 2007, respectively.

Severance and other taxes increased $0.6 million, or 3%, over levels in the third 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 9.4% and 11.5% in the third 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 in the third quarter of 2008 compared to the third quarter of 2007, the overall percentage of severance costs to sales also decreased. The third quarter of 2008 also benefited from certain deep well severance tax credits which lowered both severance tax expense and the ratio of severance tax expense to oil and gas sales.

Our total interest cost in the third quarter of 2008 was $9.0 million, of which $2.1 million was capitalized. Our total interest cost in the third quarter of 2007 were $7.9 million, of which $2.2 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the third 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 third quarters of 2008 and 2007, we recorded no debt retirement costs.

Our overall effective tax rate was 37.0% and 39.6% for the third quarters of 2008 and 2007, respectively. The effective tax rate for the third 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 third quarter of 2008 of $62.3 million was 45% higher than third quarter of 2007 income from continuing operations of $42.9 million due to higher commodity prices which were partially offset by increased costs.

Net Income. Our net income in the third quarter of 2008 of $61.9 million was 46% higher than our third quarter of 2007 net income of $42.3 million, mainly due to higher commodity prices which were partially offset by increased costs.

Results of Continuing Operations — Nine months ended September 30, 2008 and 2007

Revenues. Our revenues in the first nine months of 2008 increased by 48% compared to revenues in the same period in 2007, due to higher commodity prices which were partially offset by lower production. Crude oil production was 54% of our production volumes in the first nine months of 2008 and 69% of our production in the first nine months of 2007. Natural gas production was 34% of our production volumes in the first nine months of 2008 and 25% in the first nine months of 2007.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the nine months ended September 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	$ 418.0	$ 344.4	4,086	5,510
North Lafayette	69.3	32.7	746	631
South Lafayette	47.8	32.6	572	636
South Texas	132.7	39.5	2,036	896
Other	9.5	7.3	143	152
Total	$ 677.3	$ 456.5	7,583	7,825

Our 2008 production was adversely affected by Hurricanes Gustav and Ike. As a result of these hurricanes, approximately 0.5 MBoe of production was shut-in during the third quarter of 2008 predominantly in South Louisiana.

Oil and gas sales for the first nine months of 2008 increased by 48%, or $220.7 million, from the level of those revenues for the comparable 2007 period, while our net sales volumes in the first nine months of 2008 decreased by 3%, or 0.2 MMBoe, over net sales volumes in the first nine months of 2007. Average prices for oil increased to $115.50 per Bbl in the first nine months of 2008 from $66.76 per Bbl in the first nine months of 2007. Average natural gas prices increased to $9.43 per Mcf in the first nine months of 2008 from $6.32 per Mcf in the first nine months of 2007. Average NGL prices increased to $65.87 per Bbl in the first nine months of 2008 from $44.90 per Bbl in the first nine months of 2007.

In the first nine months of 2008, our $220.7 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $265.9 million favorable impact on sales, of which $198.5 million was attributable to the 73% increase in average oil prices received, $18.9 million was attributable to the 47% increase in NGL prices, and $48.5 million was attributable to the 49% increase in natural gas prices: offset by
- Volume variances that had a $45.2 million unfavorable impact on sales, with $90.5 million of decreases attributable to the 1.4 million Bbl decrease in oil sales volumes, offset by a $19.9 million increase due to the 0.4 million Bbl increase in NGL sales volumes, and a $25.4 million increase due to the 4.0 Bcf increase in natural gas sales volumes;

The following table provides additional information regarding our first nine 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)	Gas (Mcf)
Nine months ended September 30, 2008	4,073	900	15.7	7,583	$ 115.50	$ 65.87	$ 9.43
Nine months ended September 30, 2007	5,428	457	11.6	7,825	$ 66.76	$ 44.90	$ 6.32

During the first nine months of 2008, we recognized a net loss of $2.7 million and during the first nine months of 2007 we recognized a $0.3 million gain, 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 $114.97 and $66.76 for the first nine months of 2008 and 2007, respectively, and our average natural gas sales price would have been $9.39 and $6.35 for the first nine months of 2008 and 2007, respectively.

Costs and Expenses. Our expenses in the first nine months of 2008 increased $70.5 million, or 24%, compared to expenses in the same period of 2007.

Our first nine months of 2008 general and administrative expenses, net, increased $4.8 million, or 19%, 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. For the first nine months of 2008 and 2007, our capitalized general and administrative costs totaled $22.8 million and $19.6 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.00 per Boe in the first nine months of 2008 from $3.26 per Boe in the first nine months of 2007. The portion of supervision fees recorded as a reduction to general and administrative expenses was $11.5 million and $8.0 million for the nine month periods ended September 30, 2008 and 2007, respectively.

DD&A increased $28.0 million, or 21%, in the first nine months of 2008 from levels in the first nine months of 2007. The increase is due to increases in the depletable oil and natural gas property base, partially offset by increases in reserves from prior year levels and lower production in the 2008 period. 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 $21.36 and $17.12 in the first nine months of 2008 and 2007, respectively, resulting from increases in the per unit cost of reserves additions.

We recorded $1.4 million and $1.0 million of accretions to our asset retirement obligation in the first nine months of 2008 and 2007, respectively.

Our lease operating costs increased $30.2 million, or 61%, 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, higher natural gas and NGL processing costs in 2008, and costs related to clean-up and repair activities related to hurricanes Gustav and Ike in the third quarter of 2008. Our lease operating costs per Boe produced were $10.55 and $6.36 in the first nine months of 2008 and 2007, respectively.

Severance and other taxes increased $15.8 million, or 30%, over levels in the first nine 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 10.2% and 11.7% in the first nine 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 nine months of 2008 compared to the first nine months of 2007, the overall percentage of severance costs to sales also decreased.

Our total interest cost in the first nine months of 2008 was $29.9 million, of which $6.0 million was capitalized. Our total interest cost in the first nine months of 2007 was $26.9 million, of which $7.2 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the first nine 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 and a partial pay-down of our line of credit balance from the sale of our New Zealand assets in June 2008.

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 36.7% and 38.2% for the first nine months of 2008 and 2007. The effective tax rate for the first nine 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 nine months of 2008 of $195.4 million was 96% higher than first nine months of 2007 income from continuing operations of $99.9 million due to higher commodity prices which were partially offset by increased costs.

Net Income. Our net income in the first nine months of 2008 of $192.2 million was 90% higher than our first nine months of 2007 net income of $101.4 million, mainly due to higher commodity prices which were partially offset by increased costs.

Full-Cost Ceiling Test

Full-Cost Ceiling Test. As described in footnote 2 of the Notes to Condensed Consolidated Financial Statements (“Summary of Significant Accounting Policies”), a full-cost ceiling test is computed quarterly. 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 continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and 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 decrease in oil and/or natural gas prices were to occur.

All of 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 August 2008, we completed the sale of 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. All payments under this sale agreement are secured by unconditional letters of credit. In connection with the sale of our last permit, a third-party has brought suit against Swift Energy for breach of contract related to obtaining their consent for the transfer of the permit. The third-party has also brought suit against the New Zealand Ministry of Economic Development which challenges the transfer of this permit from Swift Energy to the purchaser. We have evaluated the situation and believe we have not met the revenue recognition criteria at this time for the permit sale, and have deferred the potential gain on this property sale pending the outcome of this litigation.

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 nine months 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 $3.6 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.

As of September 30, 2008, operations in New Zealand represented less than 1% of our total assets and approximately 5% of our first nine months of 2008 sales volumes. 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):

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	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Oil and gas sales	$ ---	$ 9,524	$ 14,675	$ 31,694
Other revenues	(17)	320	764	1,027
Total revenues	(17)	9,844	15,439	32,721
Depreciation, depletion, and amortization	(52)	5,137	4,857	16,887
Other operating expenses	314	6,169	10,450	16,196
Non-cash write-down of property and equipment	285	---	3,581	---
Total expenses	547	11,306	18,888	33,083
Loss from discontinued operations before income taxes	(564)	(1,462)	(3,449)	(362)
Income tax benefit	(216)	(829)	(301)	(1,859)
Loss from discontinued operations, net of taxes	$ (348)	$ (633)	$ (3,148)	$ 1,497
Loss per common share from discontinued operations, net of taxes-diluted	$ (0.01)	$ (0.02)	$ (0.10)	$ 0.05
Total sales volumes (MBoe)	---	324	415	1,079
Oil sales volumes (MBbls)	---	48	58	172
Natural gas sales volumes (Bcf)	---	1.4	1.8	4.6
NGL sales volumes (MBbls)	---	41	52	136
Average sales price per Boe	---	$ 29.37	$ 35.37	$ 29.37
Oil sales price per Bbl	---	$ 74.92	$ 108.16	$ 71.06
Natural gas sales price per Mcf	---	$ 3.32	$ 3.55	$ 3.35
NGL sales price per Bbl	---	$ 30.17	$ 37.66	$ 29.16
Lease operating cost per Boe	---	$ 11.18	$ 15.06	$ 9.43
Cash flow provided by (used in) operating activities	$ (875)	$ 5,427	$ 5,815	$ 18,099
Capital expenditures	---	$ 1,559	$ 2,013	$ 9,095

Total New Zealand assets at September 30, 2008 and December 31, 2007 were $10.6 million and $110.6 million, respectively.

Loss from discontinued operations, net of tax, for the third quarter of 2008 decreased compared to the same period of 2007 as the majority of our assets were sold in the second quarter of 2008 and day to day operations ceased. The loss from discontinued operations, net of tax, for the nine months ended September 30, 2008 increased compared to the same period in 2007 due to a non-cash write-down of property and equipment and lower oil and natural gas sales volumes, partially offset by lower depletion expense and other operating costs, all related to the sale of the majority of our assets. Our capitalized general and administrative expenses were immaterial in the 2008 period and totaled $1.0 million and $3.4 million for the three months and nine months ended September 30, 2007, respectively.

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 began to decline in the third quarter of 2008 and has continued to fall into the fourth quarter of 2008. Factors such as worldwide supply disruptions, worldwide economic conditions and credit availability, 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 remained high during much of 2008 when compared to longer-term historical prices but began falling in the third quarter of 2008 and have continued to fall into the fourth quarter of 2008. North American weather conditions, the industrial and consumer demand for natural gas, economic conditions and credit availability, 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.

Credit Risk Due to Certain Concentrations

We extend credit, primarily in the form of uncollateralized oil and natural gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. From certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Credit losses in 2008 and 2007 have been immaterial.

Commitments and Contingencies

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

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.

Liquidity and Capital Resources

Recent extreme volatility in worldwide credit and financial markets, combined with rapidly falling prices for oil and natural gas, all of which began in the third quarter of 2008, is likely to have a significant impact on our cash flow, capital expenditures, and liquidity in future periods. See Overview – Financial Condition.

Net Cash Provided by Operating Activities. For the first nine months of 2008, our net cash provided by operating activities from continuing operations was $499.3 million, representing a 55% increase as compared to $322.2 million generated during the first nine months of 2007. The $177.1 million increase in 2008 was primarily due to an increase of $220.7 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 September 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 balance sheets.

Existing Credit Facility. We had borrowings of $116.6 million under our bank credit facility at September 30, 2008, and $187.0 million in borrowings at December 31, 2007. Our bank credit facility at September 30, 2008 consisted of a $500.0 million revolving line of credit with a $400.0 million borrowing base. In October 2008, our lenders reaffirmed our borrowing base and commitment amount as part of their normal recurring borrowing base review which occurs every six months. The borrowing base 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. We only have entered into derivative hedging agreements with banks in our credit facility.

Debt Maturities. Our credit facility, with a balance of $116.6 million at September 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 $100.6 million at September 30, 2008. The decrease primarily resulted from a decrease in current assets held for sale, $96.5 million at December 31, 2007 as compared to $0.6 million at September 30, 2008, as we closed the sale of substantially all of our New Zealand assets during the second quarter of 2008 and paid down a portion of our credit facility balance, along with a decrease in oil and gas sales receivables at the end of the third quarter of 2008 as we shut in production in South Louisiana as a result of hurricane activity, partially offset by a decrease in current liabilities associated with assets held for sale due to the New Zealand asset sale, lower accrued capital costs and a decrease in undistributed oil and gas revenues.

Capital Expenditures. During the first nine months of 2008, we relied upon our net cash provided by operating activities from continuing operations of $499.3 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 $473.3 million, acquisitions of $46.5 million, and to pay down a portion of our credit facility.

We completed 87 of 92 wells in the first nine months of 2008, for a success rate of 95%. A total of 16 development wells were drilled successfully in the Lake Washington area, and 31 out of 32 development wells were drilled successfully in the AWP Olmos area. In Bay de Chene, we successfully drilled four development wells, and we drilled four successful development wells in the South Bearhead Creek area, successfully drilled 26 of 27 development wells in the Cotulla area, drilled two successful development wells in the Horseshoe Bayou/Bayou Sale area, drilled two out of three wells successfully in the Jeanerette field, drilled one unsuccessful development well in the Masters Creek area, and drilled one successful non-operated well in Alabama. We also drilled one successful exploratory well in the Cote Blanche Island field and one unsuccessful exploratory well in the High Island field.

During the last three months of 2008, we anticipate drilling or participating in the drilling of up to an additional 10 wells in the Lake Washington region, an additional 20 wells in the South Texas region, and one well in the Lafayette North region

New Accounting Pronouncements

In February 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 and we have seen significant declines in oil and natural gas prices going into the fourth quarter of 2008.

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 and only enter into derivative agreements with banks in our credit facility. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- Price Floors – At September 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 630,000 barrels, with a weighted average floor price of $98.15 per barrel. Our oil price floors in place at September 30, 2008, are expected to cover approximately 45% to 50% of our oil production during the fourth quarter of 2008. The natural gas price floors cover notional volumes of 2,700,000 MMBtu, with a weighted average floor price of $9.15 per MMBtu. Our natural gas price floors in place at September 30, 2008, are expected to cover approximately 50% to 55% of our natural gas production during the fourth quarter of 2008. The fair value of these instruments at September 30, 2008, was $9.4 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 fourth quarters of 2008 would be $2.0 million, which represents the original amount paid for these price floors adjusted for 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. Continued volatility in both credit and commodity markets may reduce 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. From certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. 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 September 30, 2008, we had borrowings of $116.6 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 third quarter 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 third quarter 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)
07/01/08 – 07/31/08 (1)	27,994	$66.44	---	$---
08/01/08 – 08/31/08 (1)	315	$48.44	---	---
09/01/08 – 09/30/08 (1)	161	$41.99	---	---
Total	28,470	$66.10	---	$---

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

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Item 5. Other Information.

Updated Executive Employment Agreements

Effective November 4, 2008, the Company and its CEO, President, CFO, and its two Senior Vice Presidents amended and restated existing employment agreements in place since 1995 (in one instance 1999). At the same time, the Company entered into a new employment agreement with the Company's COO (these six officers are collectively referred to as the "covered officers").

The previous form of the employment agreements provided for payments upon termination of employment of between one to 1½ times annual salary (two to three times in connection with a change of control) plus one week's salary per year of employment by the Company (two weeks' per year in connection with a change of control). Under the prior agreements, none of these payments were available to the covered officers upon termination for cause. Additionally, under the previous agreement, upon termination the vesting of all outstanding unexercised options were accelerated with the dates those options first became exercisable remaining the same; upon a change of control, death or disability exercisability was accelerated. Under the updated agreements, no payments and no acceleration of equity awards occur upon termination for cause. General benefits, insurance, confidentiality and non-compete provisions are generally the same under both agreements. The updated agreements have been drafted to comply with Section 409A of the Internal Revenue Code, principally by deferring amounts payable upon termination for at least six months.

Changes made in the updated agreements include:

1. Upon voluntary termination without good reason, the Company's CEO, President and CFO receive the sum of their annual base salary and the highest of their last three cash bonuses ("total cash compensation") and the two Senior Vice Presidents receive 75% of this total cash compensation amount.

2. The updated agreements add the ability for covered officers to terminate their employment upon achieving "senior officer tenure" by providing six months' advance notice after November 1, 2009 and working full time during those six months. "Senior officer tenure" requires reaching the age of 55 and being employed by the Company for at least ten years. Termination based upon reaching senior officer tenure entitles the Company's CEO, President and CFO to receive two times the total cash compensation amount, and the other three covered officers to receive 1½ times the total cash compensation amount.

3. In the event of a change of control, cash payments to be made to the covered officers under the Company's new Change of Control Severance Plan discussed herein are increased under the agreements by 50% with respect to the Company's CEO, President and CFO and by 25% with respect to the other three covered officers. Under the prior employment agreements cash amounts were payable solely based upon there being a change of control; under the updated agreements cash payments upon a change of control occur only if the covered officers are terminated in specified circumstances between announcement of a change of control transaction and two years after it occurs.

4. For all other covered terminations, the Company's CEO, President and CFO receive three times this total cash compensation amount, and the other three covered officers receive two and a half times this total cash compensation amount;

5. Under the updated employment agreement, outstanding unexercised options held by the covered officer are immediately vested upon termination; they also become immediately exercisable except upon voluntary termination without good reason or termination upon reaching senior officer tenure, in which two cases they retain the original dates upon which they first become exercisable. Further, upon voluntary termination without good reason, all options granted six months prior to termination are forfeited.

6. Under the updated agreements the vesting of unvested restricted stock held at termination is accelerated, except upon voluntary termination without good reason. Furthermore, the acceleration of restricted stock vesting upon reaching senior officer tenure is subject to the covered officer meeting specified service requirements.

Change of Control Severance Plan

Effective November 4, 2008, the Company adopted a new Change of Control Severance Plan (the "Plan"), providing for cash payments and continued payment of benefits to all Swift Energy employees (subject to service requirements) who, in connection with a Change of Control (as defined), are terminated by the Company for any reason other than Cause (as defined), death or disability, or terminate their employment for Good Reason (as defined). The cash payments to be made equal a percentage or multiple of an employee's then current base salary plus highest cash bonus paid over the preceding 36 months ("total cash compensation"), plus a tenure payment for all non-officer employees of either two or four percent of base salary for each year of service. Generally, employees are entitled to receive 50% of their total cash compensation, while designated managerial level employees who are not officers are entitled to receive one year of total cash compensation, and officers are entitled to receive two years of total cash compensation. Medical insurance continuation is to be provided for six months for all employees other than officers (who are entitled to receive coverage continuation for one year). The Plan also contains a modified 401K match for the year of the change of control, a tax gross up payment for all Plan participants and certain provisions on deferred payment in order to comply with Section 409A of the Internal Revenue Code. The definition of change of control includes a person or group becoming beneficial owners of 40% of the Company's shares entitled to vote for directors, a cash tender offer, merger, sale of assets or business combination resulting in a change in a majority of the Swift Energy Board of Directors, Swift Energy no longer being a independent public company, or a sale of substantially all of its assets.

2005 Stock Compensation Plan

Effective November 4, 2008, the First Amended and Restated Swift Energy Company 2005 Stock Compensation Plan (the "2005 Plan") was amended to reflect certain administrative modifications, as well as two amendments made by the Board of Directors of Swift Energy pursuant to the powers granted to them by the 2005 Plan. One change to the 2005 Plan was to make mandatory an adjustment to outstanding equity awards following a capitalization event (such as a stock split or stock dividend) affecting the common stock of Swift Energy. Prior to this change, the Board of Directors of Swift Energy had discretion to make such an adjustment following a capitalization event. The other primary amendment was made to comply with Section 409A of the Internal Revenue Code.

Item 6. Exhibits.

10.1*	First Amended and Restated 2005 Stock Compensation Plan dated November 4, 2008.
10.2*	Swift Energy Company Change of Control Severance Plan dated November 4, 2008.
10.3*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Terry E. Swift dated November 4, 2008.
10.4*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Bruce H. Vincent dated November 4, 2008.
10.5*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Alton D. Heckaman dated November 4, 2008.
10.6*	Executive Employment Agreement between Swift Energy Company and Robert J. Banks dated November 4, 2008.
10.7*	Amended and Restated Executive Employment Agreement between Swift Energy Company and James P. Mitchell dated November 4, 2008.
10.8*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and James M. Kitterman dated November 4, 2008.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *Filed herewith

SIGNATURES

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

SWIFT ENERGY COMPANY
(Registrant)

Date: November 6, 2008	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: November 6, 2008	By:	/s/ David W. Wesson David W. Wesson Controller and Principal Accounting Officer

Exhibit Index

10.1*	First Amended and Restated 2005 Stock Compensation Plan
10.2*	Swift Energy Company Change of Control Severance Plan
10.3*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Terry E. Swift
10.4*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Bruce H. Vincent
10.5*	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Alton D. Heckaman
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