SWIFT ENERGY CO
Form 10-Q
August 04, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the Quarterly Period Ended June 30, 2006

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
(Address of principal executive offices)	(Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
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	29,240,768 Shares
($.01 Par Value)	(Outstanding at July 31, 2006)
(Class of Stock)	

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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries

	June 30, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 72,073,575	$ 53,004,562
Accounts receivable-		
Oil and gas sales	54,316,805	45,518,260
Joint interest owners	1,375,144	1,082,187
Other Receivables	11,626,451	3,795,080
Deferred tax asset	10,091,251	
Other current assets	17,980,159	11,655,046
Total Current Assets	167,463,385	115,055,135
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,881,432,276	1,731,866,298
Unproved properties	96,489,581	87,553,220
	1,977,921,857	1,819,419,518
Furniture, fixtures, and other equipment	24,580,227	15,313,277
	2,002,502,084	1,834,732,795
Less Accumulated depreciation, depletion, and amortization	(830,555,121)	(755,699,056)
	1,171,946,963	1,079,033,739
Other Assets:		
Debt issuance costs	7,434,390	8,026,780
Restricted assets	2,221,507	2,296,968
	9,655,897	10,323,748
	$ 1,349,066,245	$ 1,204,412,622
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 45,818,560	$ 51,973,004
Accrued capital costs	42,054,613	30,073,728
Accrued interest	8,506,805	8,508,196
Undistributed oil and gas revenues	9,400,634	7,866,086
Total Current Liabilities	105,780,612	98,421,014

Long-Term Debt	350,000,000	350,000,000
Deferred Income Taxes	178,888,868	129,306,891
Asset Retirement Obligation	19,811,717	19,095,368
Lease Incentive Obligation	1,847,490	271,182
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, 29,649,138 and 29,458,974 shares issued, and 29,222,052 and 29,009,530 shares outstanding, respectively	296,491	294,590
Additional paid-in capital	369,191,727	365,085,695
Treasury stock held, at cost, 427,086 and 449,444 shares, respectively	(6,124,944)	(6,445,586)
Unearned compensation		(5,849,820)
Retained earnings	329,785,711	254,302,757
Accumulated other comprehensive loss, net of income tax	(411,427)	(69,469)
	692,737,558	607,318,167
	$ 1,349,066,245	$ 1,204,412,622

See accompanying notes to condensed consolidated financial statements.

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Condensed Consolidated Statements of Income
Swift Energy Company and Subsidiaries

	Three Months Ended		Six Months Ended	
	06/30/06	06/30/05	06/30/06	06/30/05
Revenues:				
Oil and gas sales	$ 144,993,977	$ 104,922,400	$ 279,946,970	$ 200,443,733
Price-risk management and other, net	2,183,269	(622,475)	3,399,207	(523,124)
	147,177,246	104,299,925	283,346,177	199,920,609
Costs and Expenses:				
General and administrative, net	7,618,054	4,995,887	15,304,963	9,870,195
Depreciation, depletion and amortization	38,877,234	28,777,631	74,283,731	52,983,009
Accretion of asset retirement obligation	202,752	187,495	494,267	374,002
Lease operating costs	18,523,049	11,565,223	32,917,538	22,614,005
Severance and other taxes	15,967,270	10,708,754	30,720,876	19,911,835
Interest expense, net	5,799,187	6,286,894	11,660,106	12,630,903
	86,987,546	62,521,884	165,381,481	118,383,949
Income Before Income Taxes	60,189,700	41,778,041	117,964,696	81,536,660
Provision for Income Taxes	22,021,252	13,896,383	42,481,742	27,965,850
Net Income	$ 38,168,448	$ 27,881,658	$ 75,482,954	$ 53,570,810
Per Share Amounts				
Basic: Net Income	$ 1.31	$ 0.98	$ 2.59	$ 1.90
Diluted: Net Income	$ 1.27	$ 0.96	$ 2.52	$ 1.86
Weighted Average Shares Outstanding	29,160,123	28,376,518	29,115,944	28,268,733

See accompanying notes to condensed consolidated financial statements.

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Condensed Consolidated Statements of Stockholders Equity
Swift Energy Company and Subsidiaries

	Common Stock(1)	Additional Paid-In Capital	Treasury Stock	Unearned Compensation	Retained Earnings	Other Comprehensive Income (Loss)	Total
Balance, December 31, 2004	$ 285,706	$ 343,536,298	$ (6,896,245)	$ (1,728,585)	$ 138,524,301	$ 450,665	$ 474,172,140
Stock issued for benefit plans (31,424 shares)		435,134	450,659				885,793
Stock options exercised (840,847 shares)	8,409	9,804,555					9,812,964
Tax benefits from exercise of stock options		4,366,236					4,366,236
Employee stock purchase plan (32,495 shares)	325	642,354					642,679
Issuance of restricted stock (15,000 shares)	150						150
Grants of restricted stock (158,500 shares)		6,668,608		(6,072,008)			596,600
Forfeitures of restricted stock		(367,490)		367,490			
Amortization of restricted stock compensation				1,583,283			1,583,283
Comprehensive Income:							
Net income					115,778,456		115,778,456
Other Comprehensive Income						(520,134)	(520,134)
Total Comprehensive Income							115,258,322
Balance, December 31,	$ 294,590	$ 365,085,695	$ (6,445,586)	$ (5,849,820)	$ 254,302,757	$ (69,469)	$ 607,318,167

2005

Stock issued for benefit plans (22,358 shares)		714,049	320,642				1,034,691
Stock options exercised (147,360 shares)	1,473	2,407,940					2,409,413
Adoption of SFAS No. 123R		(5,875,280)		5,849,820			(25,460)
Excess tax benefits from stock-based awards		1,407,367					1,407,367
Employee stock purchase plan (22,028 shares)	220	671,110					671,330
Issuance of restricted stock (20,776 shares)	208	(208)					
Amortization of stock compensation		4,781,054					4,781,054
Comprehensive Income:							
Net income					75,482,954		75,482,954
Other Comprehensive Income						(341,958)	(341,958)
Total Comprehensive Income							75,140,996
Balance, June 30, 2006	$ 296,491	$ 369,191,727	$ (6,124,944)	$	$ 329,785,711	$ (411,427)	$ 692,737,558

(1) $.01 Par Value

See accompanying notes to condensed consolidated financial statements.

Condensed Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries

	Six Months Ended June 30, 2006	2005
Cash Flows from Operating Activities:		
Net income	$ 75,482,954	$ 53,570,810
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	74,283,731	52,983,009
Accretion of asset retirement obligation	494,267	374,002
Deferred income taxes	41,098,065	27,565,850
Stock-based compensation expense	3,241,254	407,872
Other	(2,817,045)	(378,632)
Change in assets and liabilities-		
Increase in accounts receivable	(9,091,502)	(4,738,848)
Increase in accounts payable and accrued liabilities	516,464	113,433
Increase in income taxes payable	548,676	88,684
Decrease in accrued interest	(1,391)	(702,449)
Net Cash Provided by Operating Activities	183,755,473	129,283,731
Cash Flows from Investing Activities:		
Additions to property and equipment	(183,855,738)	(101,766,582)
Proceeds from the sale of property and equipment	20,305,525	2,339,634
Net cash distributed as operator of oil and gas properties	(5,910,556)	(3,840,937)
Net cash received as operator of partnerships and joint ventures	225,520	243,286
Other	572,334	50,105
Net Cash Used in Investing Activities	(168,662,915)	(102,974,494)
Cash Flows from Financing Activities:		
Payments of bank borrowings		(7,500,000)
Net proceeds from issuances of common stock	3,080,743	3,998,935
Excess tax benefits from stock-based awards	895,712	
Net Cash Provided by (Used in) Financing Activities	3,976,455	(3,501,065)
Net Increase in Cash and Cash Equivalents	$ 19,069,013	$ 22,808,172
Cash and Cash Equivalents at Beginning of Period	53,004,562	4,920,118
Cash and Cash Equivalents at End of Period	$ 72,073,575	$ 27,728,290

Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$ 11,078,838	$ 12,798,576
Cash paid during period for income taxes	$ 835,000	$ 400,000

See accompanying notes to condensed 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 and reflect necessary adjustments, all of which were of a recurring nature, 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 the latest Annual Report on Form 10-K as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

Holding Company Structure

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

Property and Equipment

We follow the full-cost method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the six months ended June 30, 2006 and 2005, such internal costs capitalized totaled $12.6 million and $8.8 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the six months ended June 30, 2006 and 2005, capitalized interest on unproved properties totaled $4.3 million and $3.5 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

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

Future development costs are estimated property-by-property based on current economic conditions and

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

are amortized to expense as our capitalized oil and gas property costs are amortized.

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

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

Full-Cost Ceiling Test.

At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects (Ceiling Test). Our hedges at June 30, 2006 consisted of crude oil price floors with strike prices lower than the period end price but did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

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

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

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

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Swift Energy Company and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas, as well as onshore oil and natural gas reserves in New Zealand. Our undivided interests in gas processing plants, and investments in oil and gas limited partnerships where we are the general partner 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 consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Revenue Recognition

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in Accounts payable and accrued liabilities on the accompanying balance sheet. Natural gas balancing receivables are reported in Other current assets on the accompanying balance sheet when our ownership share of production exceeds sales. As of June 30, 2006, we did not have any material natural gas imbalances.

Accounts Receivable

We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both June 30, 2006 and December 31, 2005, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total Accounts receivable balances on the accompanying balance sheets. Receivables related to insurance reimbursement are computed in accordance with applicable accounting guidance; and we monitor our costs incurred and their collectibility under our insurance policies and believe all amounts recorded are recoverable.

Inventories

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

	Balance at June 30, 2006 (000's)	Balance at December 31, 2005 (000's)
Materials, Supplies and Tubulars	$ 11,754	$ 8,494
Crude Oil	1,757	916
Total	$ 13,511	$ 9,410

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
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certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage,
- estimates 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, and
- estimates made in our income tax calculations.

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 changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Income Taxes

Under SFAS No. 109, Accounting for Income Taxes, deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws. The effective tax rate for the six months ended June 30, 2006 and 2005 was higher than the U.S. Federal statutory tax rate primarily due to state income taxes, partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. As of June 30, 2006, we believe we will utilize all of our U.S. federal operating loss carryforwards during the 2006 tax year, and these amounts are classified as current in the Deferred tax asset account on the accompanying balance sheet.

Accounts Payable and Accrued Liabilities

Included in Accounts payable and accrued liabilities, on the accompanying balance sheets, at June 30, 2006 and December 31, 2005 are liabilities of approximately $9.0 million and $9.9 million, respectively, representing the amount by which checks issued, but not presented 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 June 30, 2006, we recorded $0.4 million, net of taxes of $0.2 million, of derivative losses in Accumulated other comprehensive income (loss), net of income tax on the accompanying balance sheet. The components of accumulated other comprehensive Income (loss) and related tax effects for 2006 were as follows:

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

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2005	$ (110,094)	$ 40,625	$ (69,469)
Change in fair value of cash flow hedges	(2,570,637)	951,136	(1,619,501)
Effect of cash flow hedges settled during the period	2,028,708	(751,165)	1,277,543
Other comprehensive loss at June 30, 2006	$ (652,023)	$ 240,596	$ (411,427)

Total comprehensive income was $37.3 million and $28.1 million for the second quarters of 2006 and 2005, respectively. Total comprehensive income was $75.1 and $52.8 million for the first six months of 2006 and 2005, respectively.

Price-Risk Management Activities

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

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During the second quarters of 2006 and 2005, we recognized a net gain of $1.1 million and a net loss of $0.4 million, respectively, relating to our derivative activities. During the first six months of 2006 and 2005, we recognized a net gain of $2.0 million and a net loss of $0.5 million, respectively, relating to our derivative activities. This activity is recorded in Price-risk management and other, net on the accompanying statements of income. At June 30, 2006, the Company had recorded $0.4 million, net of taxes of $0.2 million, of derivative losses in Accumulated other comprehensive income (loss), net of income tax on the accompanying 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 amount of ineffectiveness reported in Price-risk management and other, net for the first six months of 2006 and 2005 were not material. We expect to reclassify all amounts currently held in Accumulated other comprehensive income (loss), net of income tax into the statement of income within the next six months when the forecasted sale of hedged production occurs.

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 oil and natural gas, these gains or losses are reclassified from Accumulated other comprehensive income (loss), net of income tax and recorded in Price-risk management and other, net on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers.

At June 30, 2006, we had in place price floors in effect for July 2006 through the December 2006 contract month for oil that cover a portion of our domestic oil production for July 2006 to December 2006. The oil price floors cover notional volumes of 1,350,000 barrels with a weighted average floor price of $63.91 per barrel. Our oil price floors in place at June 30, 2006 are expected to cover approximately 35% to 40% of our

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

estimated domestic oil production from July 2006 to December 2006. The fair value of these instruments at June 30, 2006, was $0.5 million and is recognized on the accompanying 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 are recorded as a reduction to general and administrative, net based on our estimate of the costs incurred to operate the wells. The total amount of supervision fees charged to the wells we operate was $4.2 million and $3.8 million in the first six of months of 2006 and 2005, respectively.

Asset Retirement Obligation

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

	2006	2005
Asset Retirement Obligation recorded as of January 1	$ 19,356,367	$ 17,639,136
Accretion expense for the six months ended June 30	494,267	374,002
Liabilities incurred for new wells and facilities construction	310,657	54,622
Reductions due to sold, or plugged and abandoned wells		(277,604)
Decrease due to currency exchange rate fluctuations	(88,574)	(19,087)
Asset Retirement Obligation as of June 30.	$ 20,072,717	$ 17,771,069

At both June 30, 2006 and December 31, 2005, approximately $0.3 million of our asset retirement obligation is classified as a current liability in Accounts payable and accrued liabilities on the accompanying balance sheets.

New Accounting Pronouncements

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections: a replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires voluntary changes in accounting principles to be applied retrospectively, unless it is impracticable. SFAS No. 154 s retrospective application requirement replaces APB 20 s requirement to recognize most voluntary changes in accounting principle by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. If retrospective application for all prior periods is impracticable, the method used to report the change and the reason the retrospective application is impracticable are to be disclosed.

Under SFAS No. 154, retrospective application will be the transition method in the unusual instance that a newly issued accounting pronouncement does not provide specific transition guidance. It is expected that many pronouncements will specify transition methods other than retrospective. SFAS No. 154 is effective

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

for accounting changes made in fiscal years beginning after December 15, 2005, and the adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company has not yet determined what impact, if any, this Interpretation will have on its 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, 2005, for additional information related to these share-based compensation plans.

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

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

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the three months ended June 30, 2006, were $0.8 million, $0.5 million, $0.02, and $0.02 lower, respectively, than if we had continued to account for share-based compensation under APB Opinion No. 25 for our stock option grants. For the six months ended June 30, 2006, income before taxes, net income and basic and diluted earnings per share were $1.9 million, $1.2 million, $0.04, and $0.04 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in General and Administrative, net in the accompanying condensed consolidated statements of operations.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. In addition, we receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our condensed consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows, these benefits totaled $0.3 million and $0.9 million for the three and six months ended June 30, 2006, respectively.

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Net cash proceeds from the exercise of stock options were $2.4 million for the six months ended June 30, 2006. The actual income tax benefit realized from stock option exercises was $1.3 million for the same period.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in General and Administrative, net in the accompanying condensed consolidated statements of income, and was $1.4 million and $0.3 million for the three months ended June 30, 2006 and 2005, respectively. Stock compensation expense for the six months ended June 30, 2006, and 2005 was $3.1 million and $0.4 million. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The following table illustrates the effect on June 30, 2005 operating results and per share information had the Company accounted for share-based compensation in accordance with SFAS No. 123R. Our net income and earnings per share would have been adjusted to the following pro forma amounts:

		Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net Income:	As Reported	$ 27,881,658	$ 53,570,810
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(1,113,938)	(1,973,089)
	Pro Forma	$ 26,767,720	$ 51,597,721
Basic EPS:	As Reported	$ .98	$ 1.90
	Pro Forma	$ .94	$ 1.83
Diluted EPS:	As Reported	$ .96	$ 1.86
	Pro Forma	$ .92	$ 1.79

Stock Options

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Dividend yield	0%	0%	0%	0%
Expected volatility	39%	43%	40%	43%
Risk-free interest rate	5.1%	3.9%	4.9%	3.8%
Expected life of options (in years)	1.8	3.8	5.6	3.5
Weighted-average grant-date fair value	$9.71	$11.16	$19.33	$10.27

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

At June 30, 2006, there was $5.1 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.9 years.

The following table represents stock option activity for the six months ended June 30, 2006:

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	June 30, 2006		
		Wtd. Avg.	Wtd. Avg. Contract
	Shares	Exer. Price	Life
Options outstanding, beginning of period	2,118,179	$21.28	
Options granted	163,755	$43.57	
Options canceled	(45,180)	$21.37	
Options exercised	(176,729)	$20.45	
Options outstanding, end of period	2,060,025	$23.12	5.7 Yrs
Options exercisable, end of period	1,235,041	$22.46	4.5 Yrs

The aggregate intrinsic value of options outstanding at June 30, 2006 was $55.7 million, and the aggregate intrinsic value of options exercisable was $25.3 million. Total intrinsic value of options exercised was $3.9 million for the six months ended June 30, 2006.

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, 2005, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to five years).

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of June 30, 2006, we have unrecognized compensation expense of $9.6 million associated with these awards which are expected to be recognized over a weighted-average period of 2.3 years.

The following table represents restricted stock activity for the six months ended June 30, 2006:

	June 30, 2006	
		Wtd. Avg. Grant
	Shares	Price
Restricted shares outstanding, beginning of period	236,950	$34.79
Restricted shares granted	141,330	$43.61
Restricted shares canceled	(18,380)	$38.70
Restricted shares vested	(20,776)	$27.20
Restricted shares outstanding, end of period	339,124	$38.83

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(4) Earnings Per Share

Basic earnings per share (Basic EPS) have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share (Diluted EPS) for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants to employees using the treasury stock method. Certain of our stock options, that could potentially dilute Basic EPS in the future, were antidilutive for periods ended June 30, 2006 and 2005, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the periods ended June 30, 2006 and 2005:

	Three Months Ended June 30, 2006			2005		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 38,168,448	29,160,123	$ 1.31	$ 27,881,658	28,376,518	$ 0.98
Dilutive Securities:						
Restricted Stock		97,343			30,579	
Stock Options		770,761			601,835	
Diluted EPS:						
Net Income and Assumed Share Conversions	$ 38,168,448	30,028,227	$ 1.27	$ 27,881,658	29,008,932	$ 0.96

	Six Months Ended June 30, 2006			2005		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 75,482,954	29,115,944	$ 2.59	$ 53,570,810	28,268,733	$ 1.90
Dilutive Securities:						
Restricted Stock		99,189			25,781	
Stock Options		781,536			554,986	
Diluted EPS:						
Net Income and Assumed Share Conversions	$ 75,482,954	29,996,669	$ 2.52	$ 53,570,810	28,849,500	$ 1.86

Options to purchase approximately 2.1 million shares at an average exercise price of $23.12 were outstanding at June 30, 2006, while options to purchase 2.6 million shares at an average exercise price of $20.10 were outstanding at June 30, 2005. Approximately 1.5 million and 0.3 million stock options and non-vested shares of restricted stock were not included in the computation of Diluted EPS for the three-month periods ended June 30, 2006, and 2005, respectively, and 1.5 million and 0.7 million options and non-vested shares of restricted stock were not included in the computation of Diluted EPS for the six-month periods ended June 30, 2006, and 2005, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods.

(5) Long-Term Debt

Our long-term debt, including the current portion, as of June 30, 2006 and December 31, 2005, was as follows (in thousands):

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	June 30, 2006	December 31, 2005
Bank Borrowings	$	$
7-5/8% senior notes due 2011	150,000	150,000
9-3/8% senior subordinated notes due 2012	200,000	200,000
Long-Term Debt	$ 350,000	$ 350,000

Bank Borrowings

At June 30, 2006, we had no outstanding borrowings under our $400.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2008. The interest rate is either (a) the lead bank s prime rate (8.25% at June 30, 2006) 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 June 2004, we renewed this credit facility, increasing the facility to $400 million from $300 million and extending its expiration to October 1, 2008 from October 1, 2005. The other terms of the credit facility, such as the borrowing base amount and commitment amount, stayed largely the same. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.4 million of debt issuance costs related to the renewal of this facility in 2004, which is included in Debt issuance costs on the accompanying 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 $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $15.0 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 or 9-3/8% senior subordinated notes due 2012. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group at $250.0 million effective May 1, 2006. We requested that the commitment amount with our bank group be reduced to $150.0 million effective May 9, 2003. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is in November 2006.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.2 million and $0.2 million for the three months ended June 30, 2006 and 2005, respectively, and $0.4 million and $0.6 million for the six months ended June 30, 2006 and 2005, respectively. The amount of commitment fees included in interest expense, net was $0.1 million for both the three months ended June 30, 2006 and 2005, respectively, and $0.3 million and $0.3 million for both the six months ended June 30, 2006 and 2005, respectively.

Senior Notes Due 2011

These notes consist of $150.0 million of 7-5/8% senior notes due 2011, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. In addition, prior to July 15, 2007, we may redeem up to

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35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in Debt issuance costs on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $3.0 million for both the three months ended June 30, 2006 and 2005, respectively, and $6.0 million and $5.9 million for the six months ended June 30, 2006 and 2005, respectively.

Senior Subordinated Notes Due 2012

These notes consist of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 16, 2002, and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank credit facility and 7-5/8% senior notes. Interest on these notes is payable semiannually on May 1 and November 1, and commenced on November 1, 2002. On or after May 1, 2007, we may redeem these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we could have redeemed up to 33.33% of these notes with the net proceeds of qualified offerings of our equity at 109.375% of the principal amount of these notes, plus accrued and unpaid interest. Upon certain changes in control of Swift Energy, each holder of these notes will have the right to require us to repurchase 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 subordinated notes.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $4.8 million for both the three months ended June 30, 2006 and 2005, respectively, and $9.6 million for both the six months ended June 30, 2006 and 2005.

The aggregate maturities on our long-term debt are $150 million for 2011 and $200 million for 2012.

We have capitalized interest on our unproved properties in the amount of $2.2 million and $1.7 million for the three months ended June 30, 2006 and 2005, respectively, and $4.3 million and $3.5 million for the six months ended June 30, 2006 and 2005, respectively.

(6) Foreign Activities

As of June 30, 2006, our gross capitalized oil and gas property costs in New Zealand totaled approximately $321.5 million. Approximately $298.8 million has been included in the Proved properties portion of our oil and gas properties, while $22.7 million is included as Unproved properties. Our functional currency in New Zealand is the U.S. Dollar. Net assets of our New Zealand operations total $252.9 million at June 30, 2006.

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

(7) Acquisitions and Dispositions

In November 2005, we acquired interests in the South Bearhead Creek field in Central Louisiana. This field is approximately 50 miles south of our Masters Creek field. We paid approximately $24.3 million in cash for these interests. After taking into account internal acquisition costs of $2.6 million, and assumed liabilities of $1.4 million, our total cost was $28.3 million. We allocated $26.2 million of the acquisition price to Proved properties, $2.5 million to Unproved properties, and recorded a liability for $0.4 million to Asset retirement obligation on our accompanying consolidated balance sheet. In December 2005, we acquired additional interests in this field. We paid approximately $4.6 million in cash for these additional interests. After taking into account internal acquisition costs of $0.6 million, our total cost was $5.2 million. We allocated $4.9 million of the acquisition price to Proved properties, $0.4 million to Unproved properties, and recorded a liability for $0.1 million to Asset retirement obligation on our accompanying consolidated balance sheets. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in this area. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward, however, given the acquisitions were in November and December 2005, these amounts were immaterial for 2005.

In April 2006, we sold our minority interests in the Brookeland and Masters Creek natural gas processing plants for approximately $20.3 million in cash. Under the full-cost method of accounting for oil and gas property and equipment costs, the proceeds of this sale were applied against our oil and gas properties and equipment balance, and no gain or loss was recognized on this transaction.

(8) Condensed Consolidating Financial Information

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

Condensed Consolidating Balance Sheets

(in 000's)	June 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$	$ 148,823	$ 18,640	$	$ 167,463
Property and equipment		940,775	231,172		1,171,947
Investment in subsidiaries (equity method)	692,738		491,017	(1,183,755)	
Other assets		39,962	598	(30,904)	9,656
Total assets	$ 692,738	$ 1,129,560	$ 741,427	$ (1,214,658)	$ 1,349,066

LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$	$ 96,681	$ 9,100	$	$ 105,781
Long-term liabilities		541,862	39,590	(30,904)	550,548
Stockholders equity	692,738	491,017	692,738	(1,183,755)	692,738
Total liabilities and stockholders equity	$ 692,738	$ 1,129,560	$ 741,427	$ (1,214,658)	$ 1,349,066

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(in 000's)	December 31, 2005				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$	$ 92,788	$ 22,267	$	$ 115,055
Property and equipment		862,717	216,316		1,079,034
Investment in subsidiaries (equity method)	607,318		410,612	(1,017,930)	
Other assets		31,955	682	(22,313)	10,324
Total assets	$ 607,318	$ 987,460	$ 649,877	$ (1,040,243)	$ 1,204,413
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$	$ 85,472	$ 12,949	$	$ 98,421
Long-term liabilities		491,376	29,610	(22,313)	498,674
Stockholders equity	607,318	410,612	607,318	(1,017,930)	607,318
Total liabilities and stockholders equity	$ 607,318	$ 987,460	$ 649,877	$ (1,040,243)	$ 1,204,413

Condensed Consolidating Statements of Income

(in 000's)	Three Months Ended June 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$	$ 133,363	$ 13,814	$	$ 147,177
Expenses		75,184	11,803		86,988
Income (loss) before the following:		58,179	2,011		60,190
Equity in net earnings of subsidiaries	38,168		36,641	(74,809)	
Income before income taxes	38,168	58,179	38,651	(74,809)	60,190

Income tax provision (benefit)		21,538	483		22,021
Net income	$ 38,168	$ 36,641	$ 38,168	$ (74,809)	$ 38,168

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SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in 000's)	Six Months Ended June 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$	$ 252,801	$ 30,545	$	$ 283,346
Expenses		140,982	24,399		165,381
Income (loss) before the following:		111,819	6,146		117,965
Equity in net earnings of subsidiaries	75,483		70,468	(145,951)	
Income before income taxes	75,483	111,819	76,614	(145,951)	117,965
Income tax provision (benefit)		41,351	1,131		42,482
Net income	$ 75,483	$ 70,468	$ 75,483	$ (145,951)	$ 75,483

(in 000's)	Three Months Ended June 30, 2005			
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ 88,958	$ 15,342	$	$ 104,300
Expenses	51,446	11,076		62,522
Income (loss) before the following:	37,512	4,266		41,778
Equity in net earnings of subsidiaries	4,129		(4,129)	
Income before income taxes	41,641	4,266	(4,129)	41,778
Income tax provision (benefit)	13,760	137		13,897
Net income	$ 27,881	$ 4,129	$ (4,129)	$ 27,881

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(in 000's)	Six Months Ended June 30, 2005			
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ 165,726	$ 34,197	$ (2)	$ 199,921
Expenses	95,883	22,503	(2)	118,384
Income (loss) before the following:	69,843	11,694		81,537
Equity in net earnings of subsidiaries	9,508		(9,508)	
Income before income taxes	79,351	11,694	(9,508)	81,537
Income tax provision (benefit)	25,780	2,186		27,966
Net income	$ 53,571	$ 9,508	$ (9,508)	$ 53,571

Condensed Consolidating Statements of Cash Flows

(in 000's)	Six Months Ended June 30, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$	$ 160,938	$ 22,817	$	$ 183,755
Cash flow from investing activities		(139,553)	(37,744)	8,635	(168,663)
Cash flow from financing activities		3,976	8,635	(8,635)	3,976
Net increase in cash	$	$ 25,361	$ (6,292)	$	$ 19,069
Cash, beginning of period		44,911	8,094		53,005
Cash, end of period	$	$ 70,272	$ 1,802	$	$ 72,074

(in 000's) Six Months Ended June 30, 2005

	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ 109,298	$ 19,986	$	$ 129,284
Cash flow from investing activities	(83,615)	(22,795)	3,436	(102,974)
Cash flow from financing activities	(3,501)	3,436	(3,436)	(3,501)
Net increase (decrease) in cash	22,182	627		22,809
Cash, beginning of period	205	4,715		4,920
Cash, end of period	$ 22,387	$ 5,342	$	$ 27,728

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

(9) Segment Information

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

	Three Months Ended June 30,					
	2006			2005		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	$ 131,289,669	$ 13,704,308	$ 144,993,977	$ 89,931,241	$ 14,991,159	$ 104,922,400
Costs and Expenses:						
Depreciation, depletion and amortization	31,972,663	6,904,571	38,877,234	22,558,462	6,219,169	28,777,631
Accretion of asset retirement obligation	165,484	37,268	202,752	154,166	33,329	187,495
Lease operating costs	15,413,839	3,109,210	18,523,049	8,503,723	3,061,500	11,565,223
Severance and other taxes	15,098,078	869,192	15,967,270	9,728,291	980,463	10,708,754
Income from oil and gas operations	$ 68,639,605	$ 2,784,067	$ 71,423,672	$ 48,986,599	$ 4,696,698	$ 53,683,297
Price-risk management and other, net			2,183,269			(622,475)
General and administrative, net			7,618,054			4,995,887
Interest expense, net			5,799,187			6,286,894
Income Before Income Taxes			$ 60,189,700			$ 41,778,041

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

	Six Months Ended June 30,					
	2006			2005		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	$ 249,374,363	$ 30,572,607	$ 279,946,970	$ 166,707,010	$ 33,736,723	$ 200,443,733
Costs and Expenses:						
Depreciation, depletion and amortization	59,994,415	14,289,316	74,283,731	40,232,160	12,750,849	52,983,009
Accretion of asset retirement obligation	421,156	73,111	494,267	308,023	65,979	374,002
Lease operating costs	26,721,399	6,196,139	32,917,538	16,747,940	5,866,065	22,614,005
Severance and other taxes	28,706,015	2,014,861	30,720,876	17,758,977	2,152,858	19,911,835
Income from oil and gas operations	$ 133,531,378	$ 7,999,180	$ 141,530,558	$ 91,659,910	$ 12,900,972	$ 104,560,882
Price-risk management and other, net			3,399,207			(523,124)
General and administrative, net			15,304,963			9,870,195
Interest expense, net			11,660,106			12,630,903
Income Before Income Taxes			$ 117,964,696			$ 81,536,660
Total Assets	$ 1,096,205,065	$ 252,861,180	$ 1,349,066,245	$ 845,685,920	$ 228,668,834	$ 1,074,354,754

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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, 2005. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see Forward-Looking Statements on page 37 of this report.

Overview

Swift Energy had record net income for the second quarter 2006. Net income increased 37% to $38.2 million and production increased 2% to 16.3 Bcfe over second quarter 2005 levels. For the first six months of 2006, net income increased 41% to $75.5 million and production increased 5% to 32.9 Bcfe over amounts in the same period in 2005. Cash flow from operating activities increased 54% to $99.9 million in the second quarter of 2006 over second quarter 2005 levels, and increased 42% to $183.8 million for the first half of 2006 over the first half of 2005 levels. We also had record revenues in both the second quarter of 2006 and first half of 2006. Our second quarter 2006 revenues of $147.2 million increased 41% over 2005 second quarter levels, and revenues for the first half of 2006 of $283.3 million increased 42% over first half of 2005 levels. The continued strong commodity prices during 2006, particularly oil prices, and increases in our domestic production supported the increase in our revenues as compared to the same periods in 2005. As a result of our domestic production increases, 65% of our second quarter production was liquid hydrocarbons, crude oil and natural gas liquids.

Our efforts and capital throughout the first six months of 2006 remained primarily focused on seismic data acquisition, infrastructure improvements and repairs, increased production, and the development of long-lived reserves through exploration and exploitation activities. We expect to continue this focus throughout 2006. We are studying our Lake Washington facilities to implement efficiency gains and further capacity increases. We have completed the new 3-D seismic survey over the Cote Blanche Island area in the third quarter of 2006, and have recently acquired seismic on our offshore Kaheru exploration permit in New Zealand.

Our overall costs and expenses increased in the first half of 2006. The largest increase in these costs and expenses is due to continued hurricane repair expenses and continued increased costs across the industry for equipment, services and personnel. We experienced higher costs due to increased oil production in South Louisiana along with higher severance taxes due to increased revenues. We also saw an increase in our general and administrative expenses due to an increased workforce and stock compensation expense associated with the adoption of FAS No. 123(R). We expect these cost pressures to continue to affect the industry throughout 2006.

Our financial position remains strong and flexible, allowing us to take advantage of future opportunities for organic growth through drilling and strategic growth through acquisitions. Our financial ratios have continued to improve. Our debt to capitalization ratio was 34% at June 30, 2006 compared to 37% at year-end 2005, as debt levels remained at the same level as year-end 2005 and retained earnings increased over $75 million as a result of the current period profit. Including our cash on hand at the end of the quarter, our net debt to capital ratio would have been 29%.

Continued execution of our operational strategy in the second half of 2006 should result in another excellent year of financial performance for Swift Energy. We think that strong commodity prices will continue over the foreseeable future, based in part on forward-strip pricing. With record production of 32.9 Bcfe during the first half of 2006, we are well on our way to meeting our 2006 goal of a 14% to 18% increase in production. Swift Energy s continued focus in the South Louisiana region is producing results and we expect the significant potential in this area to become more evident in the coming quarters.

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

Production in Lake Washington averaged approximately 16,900 net barrels of oil equivalent per day, or Boe/d, during July 2006 and 16,500 Boe/d for the second quarter of 2006. We expect to exit 2006 with an average net production in Lake Washington of 18,000 Boe/d. Preliminary plans are underway to add approximately 10,000 Boe/d of new oil processing capacity over the next 18 months on the west side of the Lake Washington field. Our merged 3-D seismic data offsets around our fields in southern Louisiana have yielded success in our exploration and development activities, as demonstrated recently by the very positive test results on the Newport #10 and #8 wells in the Lake Washington area. Post stack depth migration of our 3-D data set covering over 700 square miles in southern Louisiana, which includes Lake Washington and Bay de Chene, is under way and, together with additional drilling results, should give us a better understanding of Newport s reservoirs. Production during July 2006 in our Bay de Chene and Cote Blanche Island fields averaged over 12.5 MMcfe/d, which is about triple the rate of production for these areas when we acquired them in 2004. We think that additional meaningful growth is possible out of these two fields. The SL 340 #187 well awaiting completion in Cote Blanche Island is a good example. This well has two gas pays and one possible oil pay.

We are now processing the recently completed 3-D seismic data acquisition in Cote Blanche Island, which should greatly improve our ability to identify and target additional opportunities in this area as well. Beginning in the second half of 2006 and continuing through the next several years, we expect our drilling program to demonstrate reserves potential in Bay De Chene and Cote Blanche Island similar to that of Lake Washington. Our drilling program for the second half of 2006 is to drill deeper, higher impact wells in southern Louisiana and additional development wells in South Texas and Toledo Bend, together with an impactful New Zealand exploration program.

Results of Operations Three Months Ended June 30, 2006 and 2005

Revenues. Our revenues in the second quarter of 2006 increased by 41% compared to revenues in the same period in 2005, due primarily to an increase in commodity prices and the production increase principally from our Lake Washington field. Revenues from our oil and gas sales comprised substantially all of net revenues for the second quarter of 2006 and 2005. In the second quarter of 2006, oil production made up 60% of total production, natural gas made up 35%, and NGL represented 5%. In the second quarter of 2005, oil production made up 54% of total production, natural gas made up 38%, and NGL represented 8%. The percentage of our total production from oil increased as Lake Washington production, which is predominantly oil, increased over second quarter of 2005 levels.

Our second quarter 2006 weighted average prices increased 35% to $8.91 per Mcfe from $6.60 in the second quarter of 2005, with oil prices appreciating 39% to $69.63 from $50.24, natural gas prices increasing 3% to $4.79 from $4.67, and NGL prices rising 29% to $29.72 from $22.95.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF
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SWIFT ENERGY COMPANY AND SUBSIDIARIES

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the periods ended June 30, 2006 and 2005:

	Three Months Ended June 30,			
	Oil and Gas Sales (In Millions)		**Net Oil and Gas Sales Volumes (Bcfe)**	
Area	**2006**	**2005**	**2006**	**2005**
AWP Olmos	$ 13.3	$ 13.0	1.8	1.9
Brookeland	3.3	4.1	0.4	0.7
Lake Washington	99.2	62.1	9.1	7.8
Masters Creek	3.6	4.4	0.4	0.7
Other	11.9	6.3	1.4	0.8
Total Domestic	$ 131.3	$ 89.9	13.1	11.9
Rimu/Kauri	8.7	9.2	1.7	1.9
TAWN	5.0	5.8	1.5	2.1
Total New Zealand	$ 13.7	$ 15.0	3.2	4.0
Total	$ 145.0	$ 104.9	16.3	15.9

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

	Sales Volume				**Average Sales Price**		
	Oil (MBbl)	**NGL (MBbl)**	**Gas (Bcf)**	**Combined (Bcfe)**	**Oil (Bbl)**	**NGL (Bbl)**	**Gas (Mcf)**
2006							
Three Months Ended June 30:							
Domestic	1,554	70	3.3	13.1	$69.40	$40.85	$6.12
New Zealand	82	68	2.3	3.2	$73.90	$18.14	$2.83
Total	1,636	138	5.6	16.3	$69.63	$29.72	$4.79
2005							
Three Months Ended June 30:							
Domestic	1,339	118	3.2	11.9	$50.21	$25.74	$6.13
New Zealand	87	91	2.9	4.0	$50.82	$19.30	$3.05
Total	1,426	209	6.1	15.9	$50.24	$22.95	$4.67

In the second quarter of 2006, our $40.1 million increase in oil, NGL, and natural gas sales resulted from:

Price variances that had a $33.4 million favorable impact on sales, of which $31.8 million was attributable to the 39% increase in average oil prices received, $0.7 million was attributable to the 3% increase in average gas prices received, and $0.9 million was attributable to the 29% increase in average NGL prices received; and

Volume variances that had a $6.7 million favorable impact on sales, with $10.5 million of increases coming from the 209,000 Bbl increase in oil sales volumes, offset by $2.2 million of decreases due to the 0.5 Bcf decrease in gas sales volumes, and $1.6 million of decreases attributable to the 71,000 Bbl decrease in NGL sales volumes.

Costs and Expenses. Our expenses in the second quarter of 2006 increased $24.5 million, or 39%, compared to expenses in the same period of 2005. The increase was due to a $10.1 million increase in DD&A as our depletable oil and gas property base increased, a $7.0 million increase in lease operating costs due to increases in oil production and hurricane repair costs, and a $5.3 million increase in severance and other taxes due to increased production volumes and higher commodity prices in the second quarter of 2006.

Our second quarter 2006 general and administrative expenses, net, increased $2.6 million, or 52%, from the level of such expenses in the same 2005 period. This increase was primarily due to an expansion of our workforce and an increase in stock compensation expense resulting from the adoption of SFAS No. 123R. Our stock compensation expense recorded in general and administrative, net increased by $1.1 million, net of capitalized amounts, over second quarter of 2005 levels. For the second quarters of 2006 and 2005, our capitalized general and administrative costs, including capitalized stock compensation, totaled $6.6 million and $4.7 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to the geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced increased to $0.47 per Mcfe in the second quarter of 2006 from $0.31 per Mcfe in the same 2005 period. The portion of supervision fees recorded as a reduction to general and administrative expenses was $2.2 million for the second quarter of 2006 and $2.1 million for the 2005 period.

DD&A increased $10.1 million, or 35%, in the second quarter of 2006 from the level of those expenses in the same period of 2005. Domestically, DD&A increased $9.4 million in the second quarter of 2006 due to increases in the depletable oil and gas property base, including future development costs and higher production in the 2006 period. In New Zealand, DD&A increased by $0.7 million in the second quarter of 2006 due to increases in the depletable oil and gas property base and lower reserves volumes, partially offset by lower production in the 2006 period. Our DD&A rate per Mcfe of production was $2.39 and $1.81 in the second quarters of 2006 and 2005, respectively.

We recorded $0.2 million of accretions to our asset retirement obligation in both the second quarters of 2006 and 2005.

Our lease operating costs per Mcfe produced were $1.14 in the second quarter of 2006 and $0.73 in the second quarter of 2005. Our lease operating costs in the second quarter of 2006 increased $7.0 million, or 60%, over the level of such expenses in the same 2005 period. Almost all of the increase was related to our domestic operations, which increased primarily due to hurricane-related repair costs, higher production from our South Louisiana region, and higher insurance costs. Our lease operating costs in New Zealand were $3.1 million in both the second quarters of 2006 and 2005.

In the second quarter of 2006, severance and other taxes increased $5.3 million, or 49%, over levels in the second quarter of 2005. The increase was due primarily to higher commodity prices and increased Lake Washington production. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 11.0% and 10.2% in the second quarters of 2006 and 2005, respectively.

Our total interest cost in the second quarter of 2006 was $8.0 million, of which $2.2 million was capitalized. Our total interest cost in the second quarter of 2005 was also $8.0 million, of which $1.7 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the second quarter of 2006 was primarily attributable to higher capitalized costs along with lower credit facility costs resulting from a decrease in borrowings against the credit facility.

Our overall effective tax rate was 36.6% in the second quarter of 2006 and 33.3% in the second quarter of 2005. The effective income tax rate for the second quarter of 2006 was higher than the U.S. statutory rate primarily due to state income taxes, partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. The second quarter of 2005 rate is lower due to a favorable correction in the New Zealand basis of oil and gas properties.

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Net Income. For the second quarter of 2006, our net income of $38.2 million was 37% higher, and Basic EPS of $1.31 was 33% higher, than our second quarter of 2005 net income of $27.9 million and Basic EPS of $0.98. Our Diluted EPS in the second quarter of 2006 of $1.27 was 32% higher than our second quarter 2005 Diluted EPS of $0.96. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and increased production during the second quarter of 2006.

Results of Operations Six Months Ended June 30, 2006 and 2005

Revenues. Our revenues in the first six months of 2006 increased by 42% compared to revenues in the same period in 2005, due primarily to an increase in commodity prices and the production increase principally from our Lake Washington field. Revenues from our oil and gas sales comprised substantially all of net revenues for the first half of 2006 and 2005. In the first six months of 2006, oil production made up 59% of total production, natural gas made up 35%, and NGL represented 6%. In the first six months of 2005, oil production made up 52% of total production, natural gas made up 39%, and NGL represented 9%. The percentage of our total production from oil increased as Lake Washington production, which is predominantly oil, increased over 2005 levels.

Our first six months of 2006 weighted average prices increased 34% to $8.52 per Mcfe from $6.38 in the first six months of 2005, with oil prices appreciating 33% to $65.26 from $49.00, natural gas prices increasing 14% to $5.10 from $4.46, and NGL prices rising 20% to $30.04 from $24.94.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the six months ended June 30, 2006 and 2005:

	Six Months Ended June 30,			
	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (Bcfe)	
Area	**2006**	**2005**	**2006**	**2005**
AWP Olmos	$ 28.6	$ 24.3	3.7	3.8
Brookeland	7.6	8.1	1.0	1.4
Lake Washington	184.6	113.5	17.8	14.6
Masters Creek	7.6	9.1	0.9	1.5
Other	20.9	11.7	2.5	1.6
Total Domestic	$ 249.3	$ 166.7	25.9	22.9
Rimu/Kauri	17.4	21.7	3.3	4.3
TAWN	13.2	12.0	3.7	4.2
Total New Zealand	$ 30.6	$ 33.7	7.0	8.5
Total	$ 279.9	$ 200.4	32.9	31.4

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

The following table provides additional information regarding our oil and gas sales for the six months ended June 30, 2006 and 2005:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	**NGL (MBbl)**	**Gas (Bcf)**	**Combined (Bcfe)**	**Oil (Bbl)**	**NGL (Bbl)**	**Gas (Mcf)**
2006							
Six Months Ended June 30:							
Domestic	3,041	160	6.6	25.9	$65.08	$40.24	$6.76
New Zealand	206	130	5.0	7.0	$68.02	$17.44	$2.87
Total	3,247	290	11.6	32.9	$65.26	$30.04	$5.10
2005							
Six Months Ended June 30:							
Domestic	2,523	262	6.2	22.9	$48.79	$29.05	$5.78
New Zealand	224	170	6.2	8.5	$51.35	$18.60	$3.11
Total	2,747	432	12.4	31.4	$49.00	$24.94	$4.46

In the first six months of 2006, our $79.5 million increase in oil, NGL, and natural gas sales resulted from:

Price variances that had a $61.7 million favorable impact on sales, of which $52.8 million was attributable to the 33% increase in average oil prices received, $7.4 million was attributable to the 14% increase in average gas prices received, and $1.5 million was attributable to the 20% increase in average NGL prices received; and

Volume variances that had a $17.8 million favorable impact on sales, with $24.5 million of increases coming from the 500,000 Bbl increase in oil sales volumes, offset by $3.2 million of decreases due to the 0.7 Bcf decrease in gas sales volumes, and $3.5 million of decreases attributable to the 141,000 Bbl decrease in NGL sales volumes.

Costs and Expenses. Our expenses in the first six months of 2006 increased $47.0 million, or 40%, compared to expenses in the same period of 2005. The increase was due to a $21.3 million increase in DD&A as our depletable oil and gas property base increased, a $10.8 million increase in severance and other taxes due to increased production volumes and higher commodity prices in 2006, and a $10.3 million increase in lease operating costs due to higher production and hurricane repair costs.

Our first six months of 2006 general and administrative expenses, net, increased $5.4 million, or 55%, from the level of such expenses in the same 2005 period. This increase was primarily due to an expansion of our workforce and an increase in stock compensation expense resulting from the adoption of SFAS No. 123R. Our stock compensation expense recorded in general and administrative, net increased by $2.7 million, net of capitalized amounts, over first half 2005 levels. For the six months of 2006 and 2005, our capitalized general and administrative costs, including capitalized stock compensation, totaled $12.6 million and $8.8 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to the geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced increased to $0.47 per Mcfe in the first six months of 2006 from $0.31 per Mcfe in the same 2005 period. The portion of supervision fees recorded as a reduction to general and administrative expenses was $4.2 million for the second quarter of 2006 and $3.8 million for the 2005 period.

DD&A increased $21.3 million, or 40%, in the first six months of 2006 from the level of those expenses in the same period of 2005. Domestically, DD&A increased $19.8 million in the first six months of 2006 due to

MANAGEMENT S DISCUSSION AND ANALYSIS OF
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increases in the depletable oil and gas property base, including future development costs and higher production in the 2006 period. In New Zealand, DD&A increased by $1.5 million in the first six months of 2006 due to increases in the depletable oil and gas property base and lower reserves volumes, partially offset by lower production in the 2006 period. Our DD&A rate per Mcfe of production was $2.26 and $1.69 in the first six months of 2006 and 2005, respectively.

We recorded $0.5 million and $0.4 million of accretions to our asset retirement obligation in the first six months of 2006 and 2005, respectively.

Our lease operating costs per Mcfe produced were $1.00 in the first six months of 2006 and $0.72 in the first six months of 2005. Our lease operating costs in the first six months of 2006 increased $10.3 million, or 46%, over the level of such expenses in the same 2005 period. Almost all of the increase was related to our domestic operations, which increased primarily due to higher production from our South Louisiana region, higher insurance costs, and hurricane repair costs. Our lease operating costs in New Zealand increased in the first six months of 2006 by $0.3 million due to planned maintenance work at the Waihapa production station.

In the first six months of 2006, severance and other taxes increased $10.8 million, or 54%, over levels in the first six months of 2005. The increase was due primarily to higher commodity prices and increased Lake Washington production. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 11.0% and 9.9% in the first half of 2006 and 2005, respectively.

Our total interest cost in the first six months of 2006 was $16.0 million, of which $4.3 million was capitalized. Our total interest cost in the first six months 2005 was $16.1 million, of which $3.5 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the first six months of 2006 was primarily attributable to higher capitalized costs along with lower credit facility costs resulting from a decrease in borrowings against the credit facility.

Our overall effective tax rate was 36.0% and 34.3% in the first six months of 2006 and 2005, respectively. The effective income tax rate for the first six months of 2006 was higher than the U.S. statutory rate primarily due to state income taxes, partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. For the first six months of 2005, the rate is lower due to a favorable correction in the New Zealand basis of oil and gas properties.

Net Income. For the first six months of 2006, our net income of $75.5 million was 41% higher, and Basic EPS of $2.59 was 37% higher, than our first six months of 2005 net income of $53.6 million and Basic EPS of $1.90. Our Diluted EPS in the first six months of 2006 of $2.52 was 36% higher than our first half of 2005 Diluted EPS of $1.86. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and increased production during the second quarter of 2006.

Share-Based Compensation

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

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized in the six months ended June 30, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of

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January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the three months ended June 30, 2006, were $0.8 million, $0.5 million, $0.02, and $0.02 lower, respectively, than if we had continued to account for share-based compensation under APB Opinion No. 25 for our stock option grants. For the six months ended June 30, 2006, income before taxes, net income and basic and diluted earnings per share were $1.9 million, $1.2 million, $0.04, and $0.04 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in General and Administrative, net in the accompanying condensed consolidated statements of operations.

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Dividend yield	0%	0%	0%	0%
Expected volatility	39%	43%	40%	43%
Risk-free interest rate	5.1%	3.9%	4.9%	3.8%
Expected life of options (in years)	1.8	3.8	5.6	3.5
Weighted-average grant-date fair value	$9.71	$11.16	$19.33	$10.27

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

At June 30, 2006, there was $5.1 million of unrecognized compensation cost related to stock options, which are expected to be recognized over a weighted-average period of 1.9 years, and unrecognized compensation expense of $9.6 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 2.3 years. The compensation expense for restricted stock awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest.

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Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2005 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, 2005.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last two years and is currently significantly higher when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, actions taken by OPEC, and fluctuating currency exchange rates can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain higher when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas. Such factors are beyond our control.

Income Tax Regulations

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. As of June 30, 2006, we believe we will utilize all of our domestic operating loss carryforwards during the 2006 tax year, and these amounts are classified as current in the Deferred tax asset account on the accompanying balance sheet.

On May 18, 2006 the State of Texas enacted a new tax bill that repeals the State s franchise tax for activity after calendar year 2006, replacing it with a margin tax . The franchise tax is computed on both earned surplus (based on income) and taxable capital. The Company accounts for the earned surplus portion of the franchise tax as an income tax. The Company is accounting for the entire margin tax liability as an income tax.

The Company has recomputed its Texas income tax expense by applying the franchise tax rules to its current income tax expense and recalculated its cumulative deferred income tax following the new margin tax rules. This change did not result in a significant adjustment to the Company s tax rate or its cumulative deferred tax liability.

Liquidity and Capital Resources

During the first six months of 2006, we relied upon our net cash provided by operating activities of $183.8 million and proceeds from the sale of property and equipment of $20.3 million to fund capital expenditures of $183.9 million. During the first six months of 2005, we relied upon our net cash provided by operating activities of $129.3 million to fund capital expenditures of $101.8 million and to pay down our bank borrowings by $7.5 million.

Net Cash Provided by Operating Activities. For the first six months of 2006, our net cash provided by operating activities was $183.8 million, representing a 42% increase as compared to $129.3 million generated during the same 2005 period. The $54.5 million increase in the first six months of 2006 was primarily due to an increase of $79.5 million in oil and gas sales, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher production and hurricane repair costs and higher severance taxes due to higher oil and gas revenues.

Accounts Receivable. We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both June 30, 2006 and December 31,

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2005, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total Accounts receivable balances on the accompanying balance sheets. Receivables related to insurance reimbursement are computed in accordance with applicable accounting guidance; and we monitor our costs incurred and their collectibility under our insurance policies and believe all amounts recorded are recoverable.

Bank Credit Facility. We had no borrowings under our bank credit facility at June 30, 2006 and December 31, 2005. Our bank credit facility at June 30, 2006 consisted of a $400.0 million revolving line of credit with a $250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at $250.0 million, effective May 1, 2006. We maintained the commitment amount at $150.0 million, which amount was set at our request effective May 9, 2003. 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. Our revolving credit facility includes, among other restrictions that changed somewhat as the facility was renewed and extended, requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

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

Debt Maturities. Our credit facility extends until October 1, 2008. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

Working Capital. Our working capital improved from a surplus of $16.6 million at December 31, 2005, to a surplus of $61.7 million at June 30, 2006. The improvement primarily resulted from the reclassification of our deferred tax asset, an increase in cash balances, and an increase in our accounts receivable balances, partially offset by an increase in accrued capital costs due to an increase in our drilling and facility construction activities from year-end 2005 levels.

Capital Expenditures. In the first six months of 2006, we relied upon our net cash provided by operating activities of $183.8 million and proceeds from the sale of property and equipment of $20.3 million to fund capital expenditures of $183.9 million. Our total capital expenditures of approximately $183.9 million in the first six months of 2006 included:

Domestic expenditures of $147.7 million as follows:

- $111.7 million for drilling and developmental activity costs, predominantly in our Lake Washington and AWP areas;

- $26.6 million of domestic prospect costs, principally related to our Cote Blanche Island seismic activities, prospect leasehold, and geological costs of unproved prospects;

- $9.1 million primarily for leasehold improvements in our Houston office, software, computer equipment, vehicles, furniture, and fixtures;

- and $0.3 million on gas processing plants.

New Zealand expenditures of $36.2 million as follows:

$28.8 million for drilling and developmental activity costs;

$6.6 million on prospect costs and geological costs of unproved properties;

$0.6 million on gas processing plants;

and $0.2 million for computer equipment, software, furniture, and fixtures.

We successfully completed 25 of 35 wells in the first six months of 2006, for a success rate of 71%. Domestically, we completed 23 of 31 wells for a success rate of 74%. A total of 12 wells were drilled in the Lake Washington area, of which 11 were completed, and 14 wells were drilled in the AWP Olmos area, of which eight were completed. Four additional wells were drilled successfully, one each, in Bay de Chene, Cote Blanche Island, South Bearhead Creek, and Brookeland. In Alaska, we drilled an unsuccessful exploratory well. In New Zealand, we drilled three development wells, two of which were completed, and drilled an unsuccessful exploratory well. In New Zealand, two exploration wells, the Goss and Trapper prospects, began testing in the second quarter of 2006. Both exploration prospects have intermediate depth objectives currently being tested; however, the deeper objectives in both wells were deemed non-commercial.

Our current 2006 capital expenditure budget was increased to $375 to $400 million, net of $20 to $25 million of dispositions and excluding any acquisitions. Approximately 85% of the 2006 budget is targeted for domestic activities, with about 15% planned for activities in New Zealand. We plan to spend $240 to $260 million in our South Louisiana region, which includes Lake Washington, Bay de Chene and Cote Blanche Island. The $20 to $25 million of dispositions relate to non-core properties and is inclusive of the $20 million sale of our minority interest in the Brookeland and Masters Creek natural gas processing plants. We expect that our 2006 capital expenditures to approximate our cash flows provided from operating activities during 2006, as was the case in 2005. During 2006, we may utilize our free cash flow to expand our capital budget and accelerate our drilling inventory plans to take advantage of current commodity prices, potential acquisitions, debt repayment or stock repurchases. For 2006, we are targeting an increase of 14% to 18% for total production and an increase of 5% to 8% for proved reserves, over the 2005 levels.

For the last six months of 2006, we expect to make capital expenditures of approximately $210 to $235 million. These estimated 2006 amounts include an increase due to higher drilling and services costs over prior year levels. Capital expenditures for 2005 totaled $236 million.

If producing property acquisitions become attractive during the remaining six months of 2006, we could draw on our untapped bank credit facility or explore the use of debt and/or equity offerings, along with using our cash flows in excess of capital expenditures, to fund such activity.

During the last six months of 2006, we anticipate drilling or participating in the drilling of up to an additional 8 to 10 wells in the Lake Washington area, 5 to 8 wells in the Bay de Chene and Cote Blanche Island areas, 3 to 4 wells in South Bearhead Creek, and up to 8 wells in the AWP Olmos area. In addition, we plan on drilling 2 to 4 wells in New Zealand.

Our 2006 capital expenditures continue to be focused on developing and producing long-lived reserves in South Louisiana, AWP Olmos, and Rimu/Kauri area. We expect our 2006 total production to increase over 2005 levels, primarily from our South Louisiana region. Our production in the AWP Olmos area is expected to remain relatively flat. We expect production in our other core areas to decrease as a limited amount of new drilling is currently budgeted to offset the natural production decline of these properties.

In New Zealand, we signed a natural gas supply agreement that covers production from our Rimu and Kauri wells for three and one-half years. The benefits of the new agreement are to increase our sales price from the current price, termination of our existing sales agreements which called for lower sales prices on our

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natural gas production, and the ability to separately market production from new Rimu/Kauri wells with our purchaser retaining a right of first negotiation.

New Accounting Pronouncements

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections: a replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires voluntary changes in accounting principles to be applied retrospectively, unless it is impracticable. SFAS No. 154 s retrospective application requirement replaces APB 20 s requirement to recognize most voluntary changes in accounting principle by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. If retrospective application for all prior periods is impracticable, the method used to report the change and the reason the retrospective application is impracticable are to be disclosed.

Under SFAS No. 154, retrospective application will be the transition method in the unusual instance that a newly issued accounting pronouncement does not provide specific transition guidance. It is expected that many pronouncements will specify transition methods other than retrospective. SFAS No. 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005, and the adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company has not yet determined what, if any, impact this interpretation will have on its financial position or results of operations.

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Forward Looking Statements

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

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Item 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Commodity Risk

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

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

Price Floors At June 30, 2006, we had in place price floors in effect through the December 2006 contract month for oil, which are expected to cover approximately 35% to 40% of our domestic oil production for July 2006 through December 2006. The oil floors cover notional volumes of 1,350,000 barrels, and expire at various dates from July 2006 to December 2006, with a weighted average floor price of $63.91 per barrel.

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

Customer Credit Risk

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

Foreign Currency Risk

We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand dollar. Fluctuations in rates between the New Zealand dollar and U.S. dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax obligations, all denominated in New Zealand dollars.

Interest Rate Risk

Our Senior Notes due 2011 and Senior Subordinated Notes due 2012 have fixed interest rates; consequently we are not exposed to cash flow risk from market interest rate changes on these notes. However, there is a risk that market rates will decline and the required interest payments on our Senior Notes and Senior Subordinated Notes may exceed those payments based on the current market rate. At June 30, 2006, we had no borrowings under our credit facility, which is subject to floating rates and therefore susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank s base rate would constitute 83 basis points and would not have a material adverse effect on our 2006 cash flows based on this same level or a modest level of borrowing.

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Item 4.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first six months of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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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 2005 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

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

Our annual meeting of shareholders was held on May 9, 2006. At the record date, 29,102,162 shares of common stock were outstanding and entitled to one vote per share upon all matters submitted at the meeting. At the annual meeting, Raymond E. Galvin was elected to serve as a director of Swift Energy for a one year term to expire at the 2007 annual meeting of shareholders. Clyde W. Smith, Jr., Terry E. Swift and Charles J. Swindells were elected to serve as directors of Swift Energy for three year terms to expire at the 2009 annual meeting of shareholders. These directors were elected by the following votes:

NOMINEES FOR DIRECTORS	FOR	WITHHELD
Raymond E. Galvin	25,606,262	1,214,577
Clyde W. Smith, Jr.	23,361,765	3,459,074
Terry E. Swift	23,281,261	3,539,578
Charles J. Swindells	25,526,905	1,293,934

The following two proposals were also approved at the annual meeting:

	FOR	ABSTAIN
Approval to amend Swift Energy Company s 2005 Stock Compensation Plan to increase the number of shares of common stock available for awards under the plan by up to 850,000 additional shares	20,175,519	22,458
Approval of Ratification of Ernst & Young LLP as Swift Energy Company s Independent Auditors for the fiscal year ending December 31, 2006	26,730,413	8,215

Item 5. Other Information.

On July 31, 2006, the Board of Directors of Swift Energy approved, ratified, and confirmed the Employee Stock Purchase Plan, Amended and Restated, effective as of June 1, 2006 (the ESPP). The amendments made to the ESPP were (i) to change the Plan Year (as defined in the Plan) to a calendar year beginning

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January 1 and ending December 31, (ii) to make all full-time Employees (as defined in the ESPP) at the beginning of each Plan Year eligible to participate in the ESPP, (iii) to allow Participants (as defined in the ESPP) to make quarterly decreases to their payroll deduction percentages and to disallow Participants to make quarterly increases in their payroll deduction percentages, and (iv) to make the Purchase Price of the ESPP shares equal to 85% of the lower of the fair market value of the stock on the first day of the Plan Year or the last day of the Plan Year. The ESPP is attached as an exhibit to this report.

Item 6. Exhibits.

10.1*	Employee Stock Purchase Plan (amended and restated as of June 1, 2006)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURES

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

	SWIFT ENERGY COMPANY (Registrant)
Date: August 4, 2006	By: (original signed by)
	Alton D. Heckaman, Jr. Executive Vice President & Chief Financial Officer
Date: August 4, 2006	By: (original signed by)
	David W. Wesson Controller & Principal Accounting Officer

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EXHIBIT INDEX

Exhibits.

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