NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 28, 2006

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

(Mark One)

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

OR

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

For the Transition Period from __________ to __________.

Commission File Number: 1-12534

NEWFIELD EXPLORATION COMPANY
(Exact name of Registrant as specified in its charter)

Delaware	**72-1133047**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

363 North Sam Houston Parkway East
Suite 2020
Houston, Texas 77060
(Address and Zip Code of principal executive offices)
(281) 847-6000
(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 (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No ¨

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

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨

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

Yes ¨ No þ

As of July 27, 2006, there were 130,759,065 shares of the Registrant s Common Stock, par value $0.01 per share, outstanding.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except share data)
(Unaudited)

	June 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 73	$ 39
Short-term investments	132	¾
Accounts receivable	315	370
Inventories	30	22
Derivative assets	152	10
Deferred taxes	12	46
Other current assets	98	53
Total current assets	812	540
Oil and gas properties (full cost method, of which $1,030 at June 30, 2006 and $901 at December 31, 2005 were excluded from amortization)	7,900	7,042
Less accumulated depreciation, depletion and amortization	(2,899)	(2,632)
	5,001	4,410
Furniture, fixtures and equipment, net	21	20
Derivative assets	14	17
Other assets	20	23
Deferred taxes	11	9
Goodwill	62	62
Total assets	$ 5,941	$ 5,081
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 48	$ 41
Accrued liabilities	532	454
Advances from joint owners	42	29
Asset retirement obligation	31	47
Derivative liabilities	166	99
Total current liabilities	819	670
Other liabilities	21	21
Derivative liabilities	248	209
Long-term debt	1,169	870
Asset retirement obligation	223	213
Deferred taxes	813	720

Total long-term liabilities	2,474	2,033
Commitments and contingencies (Note 5)	¾	¾
Stockholders equity:		
Preferred stock ($0.01 par value; 5,000,000 shares authorized; no shares issued)	¾	¾
Common stock ($0.01 par value; 200,000,000 shares authorized at June 30, 2006 and December 31, 2005; 130,733,915 and 129,356,162 shares issued and outstanding at June 30, 2006 and December 31, 2005, respectively)	1	1
Additional paid-in capital	1,174	1,186
Treasury stock (at cost; 1,876,880 and 1,815,594 shares at June 30, 2006 and December 31, 2005, respectively)	(31)	(27)
Unearned compensation	¾	(34)
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustment	3	(4)
Commodity derivatives	(38)	(40)
Retained earnings	1,539	1,296
Total stockholders equity	2,648	2,378
Total liabilities and stockholders equity	$ 5,941	$ 5,081

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF INCOME
(In millions, except per share data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Oil and gas revenues	$ 390	$ 446	$ 821	$ 859
Operating expenses:				
Lease operating	67	50	119	95
Production and other taxes	15	12	31	23
Depreciation, depletion and amortization	144	140	275	276
General and administrative	28	28	58	51
Other	25		(5)	
Total operating expenses	279	230	478	445
Income from operations	111	216	343	414
Other income (expenses):				
Interest expense	(24)	(19)	(42)	(37)
Capitalized interest	10	11	22	23
Commodity derivative income (expense)	46	(46)	52	(155)
Other	4	1	5	1
	36	(53)	37	(168)
Income before income taxes	147	163	380	246
Income tax provision:				
Current	1	22	12	39
Deferred	52	37	125	43
	53	59	137	82
Net income	$ 94	$ 104	$ 243	$ 164
Earnings per share:				
Basic	$ 0.74	$ 0.83	$ 1.92	$ 1.32
Diluted	$ 0.73	$ 0.82	$ 1.89	$ 1.29

Weighted average number of shares outstanding for basic earnings per share	127	125	126	125
Weighted average number of shares outstanding for diluted earnings per share	129	128	129	127

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)
(Unaudited)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Cash flows from operating activities:		
Net income	$ 243	$ 164
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	275	276
Deferred taxes	125	43
Stock-based compensation	16	4
Early redemption premium	8	
Unrealized commodity derivative (income) expense	(17)	152
Changes in operating assets and liabilities:		
Decrease in accounts receivable	104	10
Increase in inventories	(7)	(10)
Increase in other current assets	(46)	(8)
(Increase) decrease in other assets	(4)	1
Decrease in accounts payable and accrued liabilities	(6)	(5)
Decrease in commodity derivative liabilities	(15)	(10)
Increase (decrease) in advances from joint owners	13	(8)
Increase in other liabilities	3	8
Net cash provided by operating activities	692	617
Cash flows from investing activities:		
Additions to oil and gas properties	(836)	(523)
Proceeds from sale of oil and gas properties		11
Additions to furniture, fixtures and equipment	(2)	(2)
Purchases of short-term investments	(484)	
Redemption of short-term investments	352	
Net cash used in investing activities	(970)	(514)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	342	473
Repayments of borrowings under credit arrangements	(342)	(593)
Proceeds from issuance of senior subordinated notes	550	
Repayment of senior subordinated notes	(250)	
Proceeds from issuances of common stock	8	20
Stock-based compensation excess tax benefit	3	
Purchases of treasury stock	(4)	

Net cash provided by (used in) financing activities		307		(100)
Effect of exchange rate changes on cash and cash equivalents		5		(3)
Increase in cash and cash equivalents		34		
Cash and cash equivalents, beginning of period		39		58
Cash and cash equivalents, end of period	$	73	$	58

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(In millions)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in	Unearned	Retained	Accumulated Other Comprehensive Income (Loss)	Total Stockholders
	Shares	Amount	Shares	Amount	Capital	Compensation	Earnings		Equity
Balance, December 31, 2005	129.4	$ 1	(1.8)	$ (27)	$ 1,186	$ (34)	$ 1,296	$ (44)	$ 2,378
Issuance of common and restricted stock	1.3				8				8
Stock-based compensation					11				11
Treasury stock, at cost			(0.1)	(4)					(4)
Tax benefit from stock-based compensation					3				3
Adoption of SFAS No. 123(R)					(34)	34			
Comprehensive income:									
Net income							243		243
Foreign currency translation adjustment, net of tax of ($4)								7	7
Reclassification adjustments for settled hedging positions, net of tax of $12								(22)	(22)
Changes in fair value of outstanding hedging positions, net of tax of ($13)								24	24
Total comprehensive income									252
	130.7	$ 1	(1.9)	$ (31)	$ 1,174	$	$ 1,539	$ (35)	$ 2,648

Balance, June 30, 2006

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our company was founded in 1989 and initially focused on the shallow waters of the Gulf of Mexico. Today, we have a diversified asset base. Our domestic areas of operation include the onshore Gulf Coast, the Anadarko and Arkoma Basins of the Mid-Continent, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

Our financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to we, us or our are to Newfield Exploration Company and its subsidiaries.

These unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to state fairly our financial position as of, and results of operations for, the periods presented. These financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America. Interim period results are not necessarily indicative of results of operations or cash flows for a full year.

These financial statements and notes should be read in conjunction with our audited consolidated financial statements and the notes thereto included in our annual report on Form 10-K for the year ended December 31, 2005.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for natural gas and oil. Historically, the energy markets have been very volatile and it is likely that oil and gas prices will continue to be subject to wide fluctuations in the future. A substantial or extended decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and gas reserves that we can economically produce.

Use of Estimates

The preparation of our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from these estimates. Our most significant financial estimates are related to our proved oil and gas reserves.

Investments

Investments consist of highly liquid investment grade commercial paper with a maturity of less than six months. These investments are classified as available-for-sale. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component of stockholders equity. Realized gains or losses are computed based on specific identification of the securities sold.

Insurance Recoveries

During the second quarter of 2006, we recognized a $2 million benefit related to our business interruption insurance coverage as a result of Hurricanes Katrina and Rita under the caption Operating expenses Other on our consolidated statement of income. For the six months ended June 30, 2006, we recognized a total benefit of $32 million.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventories

Inventories consist primarily of tubular goods and well equipment held for use in our oil and gas operations and oil produced but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia is produced into a floating production, storage and off-loading vessel and sold periodically as a barge quantity is accumulated. The product inventory consisted of approximately 121,000 barrels of crude oil valued at cost of $3 million at June 30, 2006 and 36,000 barrels of crude oil valued at cost of $1 million at December 31, 2005. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

Foreign Currency

The British pound is the functional currency for our operations in the United Kingdom. Translation adjustments resulting from translating our United Kingdom subsidiaries British pound financial statements into U.S. dollars are included as accumulated other comprehensive income on our consolidated balance sheet and statement of stockholders equity. The functional currency for all other foreign operations is the U.S. dollar. Gains and losses incurred on currency transactions in other than a country s functional currency are recorded under the caption Other on our consolidated statement of income.

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis within the related full-cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization on our consolidated statement of income.

The change in our ARO for the six months ended June 30, 2006 is set forth below (in millions):

Balance as of January 1, 2006	$ 260
Accretion expense	7
Additions	2
Settlements	(15)
Balance as of June 30, 2006	254
Less: Current portion	31
Noncurrent ARO	$ 223

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS No. 123 (R)) to account for stock-based compensation. Among other items, SFAS No. 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting and requires companies to recognize in their financial statements the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market based restricted shares. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB 25 to account for stock-based compensation. Prior period financial statements have not been restated.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Historically we have used and we anticipate to continue to use unissued shares of stock when stock options are exercised. At June 30, 2006, we had approximately 2.5 million additional shares available for issuance pursuant to our existing employee and non-employee director plans. Of the shares available at June 30, 2006, only 1.1 million could be granted as restricted shares. Grants of restricted stock under the 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of shares issued as restricted stock.

The modified prospective method requires us to estimate forfeitures in calculating the expense related to stock-based compensation as opposed to our prior policy of recognizing the forfeitures as they occurred. We recorded a cumulative effect gain of a change in accounting principle of $1 million as a result of the adoption of this standard. Because the amount was immaterial, we included it in general and administrative expense on our consolidated statement of income.

The modified prospective method precludes changes to the grant date fair value of equity awards granted before the required effective date of adoption of SFAS No. 123(R). Any unearned compensation recorded under APB 25 related to these awards is eliminated against the appropriate equity accounts. As a result, upon adoption we eliminated $34 million of unearned compensation cost and reduced by a like amount additional paid-in capital on our consolidated balance sheet.

For the six months ended June 30, 2006, we recorded stock-based compensation expense of $16 million for all plans. Of that amount, $9 million is included in general and administrative expense on our consolidated statement of income and $7 million was capitalized. The impact to net income of adopting SFAS No. 123(R) for this period was $3 million, or $0.02 per basic and diluted share. SFAS No. 123(R) also requires tax benefits relating to excess stock-based compensation deductions to be prospectively presented in our statement of cash flows as financing cash inflows. Accordingly, for the six months ended June 30, 2006, we reported $3 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

As of June 30, 2006, there was approximately $70 million of total unrecognized compensation expense related to unvested share-based compensation plans. This compensation expense is expected to be recognized on a straight-line basis over the remaining vesting period, approximately 5 years.

Stock Options. We have granted stock options under several employee stock option and omnibus stock plans. Options generally expire ten years from the date of grant and become exercisable at the rate of 20% per year. The exercise price of options cannot be less than the fair market value per share of our common stock on the date of grant.

The fair value of the stock options granted prior to and remaining outstanding at January 1, 2006 was determined using the Black-Scholes option valuation method assuming: no dividends, a weighted average risk-free interest rate of 4.09%, expected life of 6.5 years and a weighted average volatility of 37.52%.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides information about our stock option activity for the six months ended June 30, 2006:

	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share	Weighted Average Contractual Life in Years	Aggregate Intrinsic Value (In millions) (1)
Outstanding at December 31, 2005	6.5	$ 23.60	$ 10.64	7.4	$ 171
Granted	¾	¾	¾	¾	¾
Exercised	(0.3)	21.02	7.97	¾	(8)
Forfeited	(0.2)	27.09	12.40	¾	(3)
Outstanding at June 30, 2006	6.0	$ 23.65	$ 9.87	6.8	$ 152
Exercisable at June 30, 2006	2.6	$ 19.46	$ 6.87	5.6	$ 76

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the indicated date, grant date, exercise date or forfeiture date, as applicable, exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during the six month period ended June 30, 2005 was approximately $28 million.

Restricted Shares. At June 30, 2006, our employees held 0.6 million restricted shares of our common stock that vest ratably over the service period of nine years, but vesting may be accelerated if certain targets are met. The vesting of these shares is dependant upon the employees continued service with the company.

At June 30, 2006, 1.6 million restricted shares of our common stock were outstanding that are subject to performance-based vesting criteria (substantially all of which are considered market-based restricted stock under SFAS No. 123(R)). During February 2006, certain employees received 974,000 restricted performance-based shares of our common stock. The number of these shares that ultimately vests is based upon established performance targets that will be assessed on March 1, 2009. The expense will be recognized ratably over the service period from February 2006 to March 2009. The grant date fair value of these shares was $23.20 per share for a total value of $23 million. Under the grants to our executive officers, they are permitted to retire on or after March 1, 2008, if certain other conditions are met, without forfeiting the shares granted. Substantially all of the remaining performance based shares may vest in whole or in part in 2008, 2009 and 2010. The percentage of the shares vesting, if any, in each respective year is subject to the achievement of the targets identified in the respective agreements.

Under our non-employee director restricted stock plan, immediately after each annual meeting of our stockholders, each of our non-employee directors then in office receives a number of restricted shares determined by dividing $75,000 by the fair market value of one share of our common stock on the date of the annual meeting. In addition, new directors elected after an annual meeting receive a number of restricted shares determined by dividing $75,000 by the fair market value of one share of our common stock on the date of their election. The forfeiture restrictions lapse on the day before the first annual meeting of stockholders following the date of issuance of the shares if the holder remains a director until that time. At June 30, 2006, 109,913 shares remained available for grants under the plan.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Information about the restricted shares granted during the six months ended June 30, 2006 and the change in the number of outstanding restricted shares during that period is presented below:

	Service-Based	Performance/ Market- Based	Total
	(In thousands, except per share data)		
Non-vested shares outstanding at December 31, 2005	549	801	1,350
Granted	77	974	1,051
Forfeited	(12)	(11)	(23)
Vested	(43)	(167)	(210)
Non-vested shares outstanding at June 30, 2006	571	1,597	2,168
Weighted average grant date fair value of shares granted during the period	$ 43.31	$ 23.20	$ 24.54
Total fair value of shares vesting during the period	$ 793	$ 2,772	$ 3,565

Employee Stock Purchase Plan. Pursuant to our employee stock purchase plan, for each six month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period. No employee may purchase common stock under the plan valued at more than $25,000 in any calendar year. Employees of our foreign subsidiaries are not eligible to participate.

On January 1, 2006, options to purchase 23,558 shares of our common stock at a fair value of $13.14 per share were issued under the plan. In accordance with APB 25 and related interpretations, we did not recognize any compensation expense with respect to the plan prior to the adoption of SFAS No. 123(R). The fair value of the options granted on January 1, 2006 was determined using the Black-Scholes option valuation method assuming: no dividends, a risk-free interest rate of 4.35%, expected life of 6 months and volatility of 37.6%. At June 30, 2006, 686,501 shares of our common stock remained available for issuance pursuant to the plan.

UK Bonus Plan. We have a cash bonus plan for the employees of our UK North Sea operations. The value of the bonus is determined based on the value of the shares of our UK subsidiary as determined by our Board of Directors. This plan is accounted for as a liability plan under SFAS No. 123(R) and has not been material to our financial statements.

Pro forma Disclosures. Prior to January 1, 2006, we accounted for our employee stock options using the intrinsic value method prescribed by APB 25. As required by SFAS No. 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for the three and six months ended June 30, 2005. The weighted average fair value of the options granted in the first six months of 2005 was determined using the Black-Scholes option valuation method assuming: no dividends, a weighted average risk-free interest rate of 3.87%, expected life of 6.5 years and weighted average volatility of 37.50%.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
	(In millions, except per share data)	
Net income:		
As reported (1)	$ 104	$ 164
Pro forma (2)	102	162
Basic earnings per common share		
As reported	$ 0.83	$ 1.32
Pro forma	0.81	1.30
Diluted earnings per common share		
As reported	$ 0.82	$ 1.29
Pro forma	0.80	1.27

(1) Includes stock-based compensation costs, net of related tax effects, of $2 million for the three months ended June 30, 2005 and $3 million for the six months ended June 30, 2005.

(2) Includes stock-based compensation costs, net of related tax effects, that would have been included in the determination of net income had the fair value

based method been applied, of $4 million for the three months ended June 30, 2005 and $5 million for the six months ended June 30, 2005.

New Accounting Developments

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FAS 109* (Interpretation No. 48). Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* Interpretation No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Interpretation No. 48 is effective for fiscal years beginning after December 15, 2006. Earlier application is encouraged if the company has not yet issued financial statements, including interim financial statements, in the period Interpretation No. 48 is adopted. We are reviewing the Interpretation and analyzing the potential impact, if any, of this new guidance.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted stock (using the treasury stock method).

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for the indicated periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In millions, except per share data)			
Income (numerator):				
Net income basic	$ 94	$ 104	$ 243	$ 164
Net income diluted	$ 94	$ 104	$ 243	$ 164
Weighted average shares (denominator):				
Weighted average shares basic	127	125	126	125
Dilution effect of stock options and unvested restricted stock outstanding at end of period	2	3	3	2
Weighted average shares diluted	129	128	129	127
Earnings per share:				
Basic	$ 0.74	$ 0.83	$ 1.92	$ 1.32

Diluted	$ 0.73	$ 0.82	$ 1.89	$ 1.29

The calculation of shares outstanding for diluted EPS does not include the effect of outstanding stock options to purchase 0.2 million shares for the three months ended June 30, 2005 and 0.4 million shares for the six months ended June 30, 2005 because to do so would have been antidilutive. There were no antidilutive shares for the three and six months ended June 30, 2006.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

	June 30, 2006	December 31, 2005
	(In millions)	
Subject to amortization	$ 6,870	$ 6,141
Not subject to amortization:		
Exploration wells in progress	102	56
Development wells in progress	141	107
Capitalized interest	84	71
Fee mineral interests	23	23
Other capital costs:		
Incurred in 2006	74	
Incurred in 2005	104	110
Incurred in 2004	396	413
Incurred in 2003 and prior	106	121
Total not subject to amortization	1,030	901
Gross oil and gas properties	7,900	7,042
Accumulated depreciation, depletion and amortization	(2,899)	(2,632)
Net oil and gas properties	$ 5,001	$ 4,410

We believe that substantially all of the properties associated with costs not currently subject to amortization will be evaluated within four years except the Monument Butte Field. Because of its size, evaluation of the Monument Butte Field in its entirety will take significantly longer than four years. At June 30, 2006 and December 31, 2005, $307 million and $316 million, respectively, of costs associated with the Monument Butte Field were not subject to amortization.

4. Debt:

As of the indicated dates, our long-term debt consisted of the following:

	June 30, 2006	December 31, 2005
	(In millions)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$ ¾	$ ¾
LIBOR based loans	¾	¾
Total bank revolving credit facility	¾	¾

7.45% Senior Notes due 2007	125	125
Fair value of interest rate swaps [1]	(2)	(2)
7 5/8% Senior Notes due 2011	175	175
Fair value of interest rate swaps [1]	(4)	(2)
Total senior unsecured notes	294	296
Total senior unsecured debt	294	296
8 3/8% Senior Subordinated Notes due 2012	¾	249
6 5/8% Senior Subordinated Notes due 2014	325	325
6 5/8% Senior Subordinated Notes due 2016	550	¾
Total long-term debt	$ 1,169	$ 870

(1) We have hedged $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 7 5/8% Senior Notes due 2011. The hedges provide for us to pay variable and receive fixed interest payments.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Senior Subordinated Notes

On April 13, 2006, we sold $550 million principal amount of our 6 5/8% Senior Subordinated Notes due 2016. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness, equally in right of payment to our outstanding 6 5/8% Senior Subordinated Notes due 2014, and senior to all of our future indebtedness that is expressly subordinated to the notes. We may redeem some or all of the notes at any time on or after April 15, 2011 at a redemption price stated in the indenture governing the notes. Prior to April 15, 2011, we may redeem all, but not part, of the notes at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before April 15, 2009, we may redeem up to 35% of the original principal amount of the notes with the net cash proceeds of certain sales of our common stock at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption. Like the indenture governing our other senior subordinated notes, these notes may limit our ability under certain circumstances to incur additional debt, make restricted payments, pay dividends on or redeem our capital stock, make certain investments, create liens, make certain dispositions of assets, engage in transactions with affiliates and engage in mergers, consolidations and certain sales of assets.

On May 3, 2006, we redeemed all $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012. The redemption included a premium related to the early extinguishment of the Notes of $19 million. This premium and the remaining unamortized original issuance costs of these Notes of $8 million were recorded as an expense under the caption Operating expenses Other on our consolidated statement of income.

Credit Arrangements

In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of our credit facility provide for initial loan commitments of $1 billion from a syndicate of banks, led by JPMorgan Chase as the agent bank. The loan commitments under the credit facility may be increased to a maximum aggregate amount of $1.5 billion if the lenders increase their loan commitments or new financial institutions are added to our credit facility. Loans under the credit facility bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate (LIBOR), plus a margin that is based on a grid of our debt rating (100 basis points per annum at June 30, 2006). At June 30, 2006, we had no borrowings under our credit facility.

The credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonment expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; and as long as our debt rating is below investment grade, the maintenance of an annual ratio of the calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At June 30, 2006, we were in compliance with all of our debt covenants.

As of June 30, 2006, we had $62 million of undrawn letters of credit under our credit facility. The letters of credit outstanding under the credit facility are subject to annual fees, based on a grid of our debt rating (87.5 basis points at June 30, 2006), plus an issuance fee of 12.5 basis points.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At June 30, 2006, we had no borrowings under our money market lines.

5. Contingencies:

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

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Segment Information:

While we only have operations in the oil and gas exploration and production industry, we are organizationally structured along geographic operating segments. Our operating segments are the United States, the United Kingdom, Malaysia, China and Other International. The accounting policies of each of our operating segments are the same as those described in Note 1, Organization and Summary of Significant Accounting Policies.

The following tables provide the geographic operating segment information required by SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, as well as results of operations of oil and gas producing activities required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities, as of and for the three and six months ended June 30, 2006 and 2005. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

	United States	United Kingdom	Malaysia (In millions)	China	Other International	Total
Three Months Ended June 30, 2006:						
Oil and gas revenues	$ 375	$ ¾	$ 15	$ ¾	$ ¾	$ 390
Operating expenses:						
Lease operating	62	¾	5	¾	¾	67
Production and other taxes	10	¾	5	¾	¾	15
Depreciation, depletion and amortization	141	¾	3	¾	¾	144
General and administrative	27	1	¾	¾	¾	28
Other	25	¾	¾	¾	¾	25
Allocated income taxes	40	¾	2	¾	¾	
Net income (loss) from oil and gas properties	$ 70	$ (1)	$	$ ¾	$ ¾	
Total operating expenses						279
Income from operations						111
Interest expense, net of interest income, capitalized interest and other						(10)
Commodity derivative income						46
Income before income taxes						$ 147
Total long-lived assets	$ 4,687	$ 132	$ 118	$ 57	$ 7	$ 5,001

Additions to long-lived assets	$ 398	$ 36	$ 20	$ 8	$ 1	$ 463

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Three Months Ended June 30, 2005:						
Oil and gas revenues	$ 431	$ ¾	$ 15	$ ¾	$ ¾	$ 446
Operating expenses:						
Lease operating	46	¾	4	¾	¾	50
Production and other taxes	11	¾	1	¾	¾	12
Depreciation, depletion and amortization	138	¾	2	¾	¾	140
General and administrative	28		¾	¾	¾	28
Allocated income taxes	75	¾	3	¾	¾	
Net income from oil and gas properties	$ 133	$	$ 5	$ ¾	$ ¾	
Total operating expenses						230
Income from operations						216
Interest expense, net of interest income, capitalized interest and other						(7)
Commodity derivative expense						(46)
Income before income taxes						$ 163
Total long-lived assets	$ 3,859	$ 37	$ 64	$ 38	$ 13	$ 4,011
Additions to long-lived assets	$ 249	$ 3	$ 10	$ 1	$ ¾	$ 263

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Six Months Ended June 30, 2006:						
Oil and gas revenues	$ 798	$ ¾	$ 23	$ ¾	$ ¾	$ 821

Operating expenses:						
Lease operating	112	¾	7	¾	¾	119
Production and other taxes	26	¾	5	¾	¾	31
Depreciation, depletion and amortization	271	¾	4	¾	¾	275
General and administrative	55	2	¾	1	¾	58
Other	(5)	¾	¾	¾	¾	(5)
Allocated income taxes	121	(1)	3	¾	¾	
Net income (loss) from oil and gas properties	$ 218	$ (1)	$ 4	$ (1)	$ ¾	
Total operating expenses						478
Income from operations						343
Interest expense, net of interest income, capitalized interest and other						(15)
Commodity derivative income						52
Income before income taxes						$ 380
Total long-lived assets	$ 4,687	$ 132	$ 118	$ 57	$ 7	$ 5,001
Additions to long-lived assets	$ 726	$ 78	$ 35	$ 13	$ 1	$ 853

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Six Months Ended June 30, 2005:						
Oil and gas revenues	$ 834	$ 1	$ 24	$ ¾	$ ¾	$ 859
Operating expenses:						
Lease operating	89	¾	6	¾	¾	95
Production and other taxes	22	¾	1	¾	¾	23
Depreciation, depletion and amortization	272	¾	4	¾	¾	276
General and administrative	50	1	¾	¾	¾	51
Allocated income taxes	143	¾	5	¾	¾	
Net income from oil and gas properties	$ 258	$ ¾	$ 8	$ ¾	$ ¾	
Total operating expenses						445
Income from operations						414
Interest expense, net of interest income, capitalized interest and other						(13)
Commodity derivative expense						(155)
Income before income taxes						$ 246
Total long-lived assets	$ 3,859	$ 37	$ 64	$ 38	$ 13	$ 4,011
Additions to long-lived assets	$ 480	$ 23	$ 12	$ 1	$ 1	$ 517

7. Commodity Derivative Instruments and Hedging Activities:

We utilize swap, floor, collar and three-way collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash Flow Hedges

Prior to the fourth quarter of 2005, all derivatives that qualified for hedge accounting were designated on the date we entered into the contract as a hedge of the variability in cash flows associated with the forecasted sale of our future oil and gas production. All open contracts that were designated and qualified as cash flow hedges as of September 30, 2005 will continue to be accounted for under hedge accounting until the contract expires or is otherwise settled. After-tax changes in the fair value of a derivative that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet until the sale of the hedged oil and gas production. Upon the sale of the hedged production, the net after-tax change in the fair value of the associated derivative recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives is reversed and the gain or loss on the hedge, to the extent that it is effective, is reported in Oil and gas revenues on our consolidated statement of income. Settlements of our qualifying hedge derivatives are included in operating cash flows on our consolidated statement of cash flows. At June 30, 2006, we had a net $38 million after-tax loss recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives. We expect hedged production associated with commodity derivatives accounting for a net loss of approximately $39 million to be sold within the next 12 months and hedged production associated with a remaining net gain of approximately $1 million to be sold thereafter. The actual gain or loss on these commodity derivatives could vary significantly as a result of changes in market conditions and other factors.

For those contracts designated as a cash flow hedge, we formally document all relationships between the derivative instruments and the hedged production, as well as our risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. We also formally assess (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, we will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, we will carry the derivative at its fair value on our consolidated balance sheet and recognize all subsequent changes in its fair value on our consolidated statement of income for the period in which the change occurs.

As of June 30, 2006, we had entered into contracts that qualify and were designated as cash flow hedges with respect to our future production as follows:

Natural Gas

Period and Type of Contract	Volume in MMMBtus	NYMEX Contract Price Per MMBtu Floor Contracts Range	NYMEX Contract Price Per MMBtu Floor Contracts Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
July 2006 September 2006				
Floor contracts	4,800	$ 7.35	$ 7.35	$ 6
October 2006 December 2006				
Floor contracts	1,600	7.35	7.35	2
				$ 8

Oil

Period and Type of Contract	Volume in MBbls	NYMEX Contract Price Per Bbl Swaps (Weighted Average)	Collars Floors Range		Floors Weighted Average	Ceilings Range		Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
July 2006 September 2006									
Price swap contracts	753	$ 46.83		¾	¾		¾	¾	$ (21)
Collar contracts	151	¾	$ 50.00	$55.00	$ 52.52	$ 73.90	$83.75	$ 78.84	
October 2006 December 2006									
Price swap contracts	753	46.83		¾	¾		¾	¾	(22)
Collar contracts	151	¾	50.00	55.00	52.52	73.90	83.75	78.84	
January 2007 December 2007									
Price swap contracts	605	47.66		¾	¾		¾	¾	(16)
Collar contracts	365	¾	50.00	55.00	52.50	77.10	83.25	80.18	(2)
									$ (61)

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Derivative Contracts

Beginning in the fourth quarter of 2005 we elected not to designate any additional swap, collar and floor contracts that were entered into subsequent to October 1, 2005 as accounting hedges under SFAS No. 133. These contracts and our basis contracts, as well as our three-way collar contracts, which do not qualify as cash flow hedges, are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative income (expense). Settlements of such derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

As of June 30, 2006, we had entered into contracts with respect to our future production that are not accounted for as hedges as set forth in the table below.

Natural Gas

Period and Type of Contract	Volume in MMMBtus	NYMEX Contract Price Per MMBtu: Swaps (Weighted Average)	Collars: Floors Range	Collars: Floors Weighted Average	Collars: Ceilings Range	Collars: Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
July 2006 September 2006							
Price swap contracts	13,770	$ 8.96					$ 33
Collar contracts	7,140		$ 8.00 $9.35	$ 8.55	$ 10.50 $20.00	$ 12.60	17
Floor contracts	510		8.29	8.29			1
October 2006 December 2006							
Price swap contracts	12,490	9.02					18
Collar contracts	15,880		9.00 9.50	9.17	11.00 15.40	12.71	16
January 2007 December 2007							
Price swap contracts	50,940	9.07					22
Collar contracts	26,040		9.00 9.50	9.17	11.00 15.75	12.90	(5)
							$ 102

Oil

Period and Type of Contract	Volume in MBbls	NYMEX Contract Price Per Bbl: Swaps (Weighted Average)	Additional Put Range	Additional Put Weighted Average	Collars: Floors Range	Collars: Floors Weighted Average	Collars: Ceilings Range	Collars: Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
July 2006 September 2006									
3-Way collar contracts	480		$ 30.00 $50.00	$ 37.43	$ 35.00 $60.00	$ 44.69	$ 50.50 $80.00	$ 62.21	$ (7)
October 2006 December 2006									
Price swap contracts	30	$ 70.00							

Collar contracts	60						60.00	60.00	80.50	81.00	80.75	
3-Way collar contracts	480		30.00	50.00	37.43	35.00	60.00	44.69	50.50	80.00	62.21	(8)
January 2007 December 2007												
Price swap contracts	120	70.00										(1)
Collar contracts	240						60.00	60.00	80.50	81.00	80.75	(1)
3-Way collar contracts	3,525		25.00	50.00	30.02	32.00	60.00	37.12	44.70	82.00	55.32	(75)
January 2008 December 2008												
3-Way collar contracts	3,294		25.00	29.00	26.56	32.00	35.00	33.00	49.50	52.90	50.29	(72)
January 2009 December 2009												
3-Way collar contracts	3,285		25.00	30.00	27.00	32.00	36.00	33.33	50.00	54.55	50.62	(64)
January 2010 December 2010												
3-Way collar contracts	3,645		25.00	32.00	28.60	32.00	38.00	34.90	50.00	53.50	51.52	(63)
												$ (291)

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Basis Contracts

During the second quarter of 2006, we added several natural gas basis hedges to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points as set forth in the table below.

	Onshore Gulf Coast	Offshore Gulf of Mexico	Mid-Continent	Rocky Mountains
August 2006 December 2006				
Volume in MMMBtus	21,490	1,340	9,180	500
Weighted average differential	($0.78)	$ 0.21	($1.23)	($1.83)

Commodity Derivative Income (Expense)

The following table presents information about the components of commodity derivative income (expense) for the three and six months ended June 30, 2006 and 2005.

	Three Months Ended June 30,		Six Months Ended June 30	
	2006	2005	2006	2005
	(In millions)			
Cash Flow Hedges:				
Hedge ineffectiveness	$ 1	$ 3	$ 6	$ (6)
Other Derivative Contracts:				
Unrealized gain (loss) due to changes in fair market value	9	(48)	11	(146)
Realized gain (loss) on settlement	36	(1)	35	(3)
Total commodity derivative income (expense)	$ 46	$ (46)	$ 52	$ (155)

8. Accrued Liabilities:

As of the indicated dates, our accrued liabilities consisted of the following:

	June 30, 2006	December 31, 2005
	(In millions)	
Revenue payable	$ 89	$ 117
Accrued capital costs	230	154
Accrued lease operating expense	38	33
Employee incentive expense	57	60
Accrued interest on notes	23	21
Taxes payable	18	26
Deferred acquisition payments	8	20
Other	69	23
Total accrued liabilities	$ 532	$ 454

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Comprehensive Income:

For the periods indicated, our comprehensive income (loss) consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In millions)			
Net income	$ 94	$ 104	$ 243	$ 164
Foreign currency translation adjustment, net of tax of ($4) and $2 for the three and six month periods ended June 30, 2006 and 2005, respectively	7	(4)	7	(4)
Reclassification adjustments for settled hedging positions, net of tax of $3 and $11 for the three months ended June 30, 2006 and 2005, respectively, and $12 and $10 for the six months ended June 30, 2006 and 2005, respectively	(6)	(20)	(22)	(19)
Changes in fair value of outstanding hedging positions, net of tax of ($5) and ($26) for the three months ended June 30, 2006 and 2005, respectively, and ($13) and $25 for the six months ended June 30, 2006 and 2005, respectively	9	48	24	(47)
Total comprehensive income	$ 104	$ 128	$ 252	$ 94

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our domestic areas of operation include the onshore Gulf Coast, the Anadarko and Arkoma Basins of the Mid-Continent, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flow available for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of oil and gas that we can economically produce; and
- the accounting for our oil and gas activities.

We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production to reduce our exposure to commodity price fluctuations.

Reserve Replacement. Most of our producing properties have declining production rates. As a result, to maintain and grow our production and cash flow we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves.

Significant Estimates. We believe the most difficult, subjective or complex judgments and estimates we must make in connection with the preparation of our financial statements are:

- the quantity of our proved oil and gas reserves;
- the timing of future drilling, development and abandonment activities;
- the cost of these activities in the future;
- the fair value of the assets and liabilities of acquired companies;
- the value of our derivative positions; and
- the fair value of stock-based compensation.

Other factors. Please see *Risk Factors* in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005 for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations. This report should be read together with those discussions.

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Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production, which is net of the effects of the settlement of contracts associated with our production that are accounted for as hedges. Settlement of our derivative contracts that are not accounted for as hedges has no effect on our reported revenues. Please see Note 7, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts. Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold. Revenues for the second quarter of 2006 were 12% lower than the comparable period of 2005 due to continued production deferrals related to the 2005 hurricanes, the timing of liftings in Malaysia and limited refining capacity for our Monument Butte production. Revenues for the first six months of 2006 were 4% lower than the same period of the prior year also due to production deferrals related to the 2005 hurricanes, the timing of liftings in Malaysia and limited refining capacity for our Monument Butte production, offset somewhat by higher commodity prices.

	Three Months Ended June 30,		Percentage Increase	Six Months Ended June 30,		Percentage Increase
	2006	2005	(Decrease)	2006	2005	(Decrease)
Production [1]:						
United States:						
Natural gas (Bcf)	48.0	53.3	(10%)	92.4	104.5	(12%)
Oil and condensate (MBbls)	1,462	2,044	(28%)	2,935	4,084	(28%)
Total (Bcfe)	56.8	65.6	(13%)	110.0	129.0	(15%)
International:						
Natural gas (Bcf)		0.1	(100%)		0.1	(100%)
Oil and condensate (MBbls)	253	277	(9%)	368	508	(28%)
Total (Bcfe)	1.5	1.7	(12%)	2.2	3.2	(31%)
Total:						
Natural gas (Bcf)	48.0	53.4	(10%)	92.4	104.6	(12%)
Oil and condensate (MBbls)	1,715	2,321	(26%)	3,303	4,592	(28%)
Total (Bcfe)	58.3	67.3	(13%)	112.2	132.2	(15%)
Average Realized Prices [2]:						
United States:						
Natural gas (per Mcf)	$ 6.14	$ 6.41	(4%)	$ 6.93	$ 6.32	10%
Oil and condensate (per Bbl)	54.15	43.24	25%	52.66	42.07	25%
Natural gas equivalent (per Mcfe)	6.58	6.56		7.23	6.45	12%
International:						
Natural gas (per Mcf)	$	$ 5.35	N/M(3)	$	$ 5.15	N/M(3)
Oil and condensate (per Bbl)	62.50	51.95	20%	63.53	48.27	32%
Natural gas equivalent (per Mcfe)	10.42	8.55	22%	10.59	7.92	34%
Total:						
Natural gas (per Mcf)	$ 6.14	$ 6.41	(4%)	$ 6.93	$ 6.32	10%

Oil and condensate (per Bbl)	55.38	44.28	25%	53.87	42.76	26%
Natural gas equivalent (per Mcfe)	6.68	6.61	1%	7.30	6.49	12%

(1) Represent volumes sold regardless of when produced.

(2) Average realized prices include the effects of hedging other than contracts that are not designated for hedge accounting. Had we included the effect of these contracts, our average realized price for total gas would have been $6.97 per Mcf for the second quarter and $7.38 per Mcf for the six months ended June 30, 2006. There were no gas contracts that were not designated for hedge accounting that settled in the second quarter and six months ended June 30, 2005. Our total oil and condensate average realized price would have been $52.88 per Bbl and $43.86 per

Bbl for the second quarter of 2006 and 2005, respectively, and $51.76 per Bbl and $42.05 per Bbl for the six months ended June 30, 2006 and 2005, respectively.

(3) Not meaningful.

Production. Our total oil and gas production (stated on a natural gas equivalent basis) for the second quarter of 2006 decreased 13% and for the six months ended June 30, 2006 decreased 15% over the comparable period of 2005. This decrease was primarily the result of continued Gulf of Mexico production deferrals related to the 2005 hurricanes of approximately 10 Bcfe for the six months ended June 30, 2006, natural field declines, timing of liftings in Malaysia and limited refining capacity for our Monument Butte oil production. The decrease was partially offset by successful drilling efforts in the Mid-Continent.

Natural Gas. Our second quarter and first six months of 2006 natural gas production decreased 10% and 12%, respectively, when compared to the same periods of 2005. The decrease was primarily the result of continued Gulf of Mexico production deferrals.

Crude Oil and Condensate. Our second quarter and first six months of 2006 oil and condensate production decreased 26% and 28%, respectively, when compared to the same periods of 2005. The decrease was the result of production deferrals related to the 2005 hurricanes, timing of liftings in Malaysia and limited refining capacity for our Monument Butte oil production.

Effects of Hedging Realized Prices. The following table presents information about the effects of derivative contracts designated for hedge accounting on realized prices. The effects of derivative contracts that are not designated for hedge accounting are described in the note to the table.

	Average Realized Prices		**Ratio of Hedged to Non-Hedged Price**
	With Hedge[(1)]	**Without Hedge**	
Natural Gas:			
Three months ended June 30, 2006	$ 6.14	$ 6.15	100%
Three months ended June 30, 2005	6.41	6.55	98%
Six months ended June 30, 2006	6.93	6.87	101%
Six months ended June 30, 2005	6.32	6.31	100%
Crude Oil and Condensate:			
Three months ended June 30, 2006	$55.38	$64.67	86%
Three months ended June 30, 2005	44.28	50.27	88%
Six months ended June 30, 2006	53.87	61.83	87%
Six months ended June 30, 2005	42.76	48.74	88%

(1) Average realized prices only include the effects of derivative contracts designated for hedge accounting. Had we included the effects of derivative contracts that are not designated for hedge

accounting, our average realized price for total gas would have been $6.97 per Mcf for the second quarter and $7.38 per Mcf for the six months ended June 30, 2006. There were no gas contracts that were not designated for hedge accounting that settled in the second quarter and six months ended June 30, 2005. Our total oil and condensate average realized price would have been $52.88 per Bbl and $43.86 per Bbl for the second quarter of 2006 and 2005, respectively, and $51.76 per Bbl and $42.05 per Bbl for the six months ended June 30, 2006 and 2005, respectively.

Operating Expenses. Generally, our proved reserves and production have grown steadily since our founding. As a result, our operating expenses also have increased. We believe the most informative way to analyze changes in operating expenses from period to period is on a unit-of-production, or per Mcfe, basis.

The following table presents information about our operating expenses for the second quarter of 2006 and 2005.

	Unit-of-Production (Per Mcfe) Three Months Ended June 30, 2006	2005	Percentage Increase (Decrease)	Amount (In millions) Three Months Ended June 30, 2006	2005	Percentage Increase (Decrease)
United States:						
Lease operating	$ 1.09	$ 0.70	56%	$ 62	$ 46	36%
Production and other taxes	0.20	0.17	18%	10	11	1%
Depreciation, depletion and amortization	2.48	2.11	18%	141	138	2%
General and administrative	0.48	0.41	17%	27	28	1%
Other	0.44		100%	25		100%
Total operating expenses	$ 4.69	$ 3.39	38%	$ 265	$ 223	20%
International:						
Lease operating	$ 3.09	$ 2.28	36%	$ 5	$ 4	20%
Production and other taxes	3.11	0.68	357%	5	1	304%
Depreciation, depletion and amortization	1.71	1.31	31%	3	2	15%
General and administrative	0.67	0.49	37%	1		20%
Total operating expenses	$ 8.58	$ 4.76	80%	$ 14	$ 7	59%
Total:						
Lease operating	$ 1.14	$ 0.74	54%	$ 67	$ 50	34%
Production and other taxes	0.27	0.18	50%	15	12	30%
Depreciation, depletion and amortization	2.46	2.09	18%	144	140	2%
General and administrative	0.48	0.41	17%	28	28	2%
Other	0.43		100%	25		100%
Total operating expenses	$ 4.78	$ 3.42	40%	$ 279	$ 230	22%

Domestic Operations. Our domestic operating expenses for the second quarter of 2006, stated on an Mcfe basis, increased 38% over the same period of 2005. This increase was primarily related to the following items:

Lease operating expense (LOE), on an Mcfe basis, was adversely impacted by lower production and higher operating costs.

Production and other taxes, on an Mcfe basis, increased due to higher oil and condensate prices and a 20% increase in the proportion of our production volumes subject to production taxes.

The increase in our depreciation, depletion and amortization (DD&A) rate resulted from higher cost reserve additions. The component of DD&A associated with accretion expense related to SFAS No. 143 was $0.06 per Mcfe for the second quarter of 2006 and $0.05 per Mcfe for the second quarter of 2005. The component of DD&A associated with furniture, fixture and equipment was $0.02 per Mcfe for the second quarter of 2006 and

2005.

The increase in general and administrative (G&A) expense was primarily due to stock-based compensation recognized in accordance with our adoption of SFAS No. 123 on January 1, 2006 and lower production. See Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation,* to our consolidated financial statements appearing earlier in this report. This increase was offset by a decrease in incentive compensation as a result of lower adjusted net income (as defined in our incentive compensation plan) in the second quarter of 2006 as compared to the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. We capitalized $10 million of direct internal costs in the second quarter of 2006 and 2005.

In May 2006, we redeemed all $250 million of our 8 3/8% Senior Subordinated Notes due 2012. The redemption included a premium related to early extinguishment of the Notes of $19 million and a charge of $8 million related to the remaining unamortized original issuance costs of these Notes. In the second quarter of 2006, we recorded a $2 million benefit related to our business interruption insurance coverage as a result of the operations disruptions caused by the 2005 hurricanes.

International Operations. Our international operating expenses for the second quarter of 2006 increased 59% primarily due to increased production and other taxes, which increased as a result of significantly higher crude oil prices. The 80% increase, stated on an Mcfe basis, resulted from the 12% decrease in production for the second quarter of 2006 due to the timing of liftings in Malaysia.

The following table presents information about our operating expenses for the first six months of 2006 and 2005.

	Unit-of-Production (Per Mcfe)			Amount (In million)		
	Six Months Ended June 30,		Percentage Increase	Six Months Ended June 30,		Percentage (Decrease)
	2006	2005	(Decrease)	2006	2005	Increase
United States:						
Lease operating	$ 1.02	$ 0.69	48%	$ 112	$ 89	27%
Production and other taxes	0.24	0.17	41%	26	22	21%
Depreciation, depletion and amortization	2.46	2.11	17%	271	272	
General and administrative	0.50	0.38	32%	55	50	11%
Other	(0.04)		100%	(5)		100%
Total operating expenses	$ 4.18	$ 3.35	25%	$ 460	$ 433	(16%)
International:						
Lease operating	$ 2.96	$ 1.97	50%	$ 7	$ 6	4%
Production and other taxes	2.51	0.55	356%	5	1	216%
Depreciation, depletion and amortization	1.71	1.30	32%	4	4	(9%)
General and administrative	1.46	0.46	217%	3	1	121%
Total operating expenses	$ 8.64	$ 4.28	102%	$ 18	$ 12	40%
Total:						
Lease operating	$ 1.06	$ 0.72	47%	$ 119	$ 95	25%
Production and other taxes	0.28	0.18	56%	31	23	35%
Depreciation, depletion and amortization	2.45	2.09	17%	275	276	(1%)
General and administrative	0.51	0.38	34%	58	51	14%
Other	(0.04)		100%	(5)		100%
Total operating expenses	$ 4.26	$ 3.37	26%	$ 478	$ 445	7%

Domestic Operations. Our domestic operating expenses for the first six months of 2006, stated on an Mcfe basis, increased 25% over the same period of 2005. This increase was primarily related to the following items:

Lease operating expense (LOE), on an Mcfe basis, was adversely impacted by lower production, higher operating costs and increased well workover activity.

Production and other taxes, on an Mcfe basis, increased due to higher commodity prices and a 20% increase in the proportion of our production volumes subject to production taxes.

The increase in our DD&A rate resulted from higher cost reserve additions. The component of DD&A associated with accretion expense related to SFAS No. 143 was $0.07 per Mcfe for the first six months of 2006 and $0.05 per Mcfe for the first six months of 2005. The component of DD&A associated with furniture, fixture and equipment was $0.01 per Mcfe and $0.02 per Mcfe for the first six months of 2006 and 2005, respectively.

The increase in G&A expense of $0.12 per Mcfe, or 32%, was primarily due to lower production, growth in our workforce and an increase in stock compensation expense of approximately 192% due to the adoption of SFAS No. 123(R). See Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation.* During the first six months of 2006 and 2005, we capitalized $19 million of direct internal costs.

In May 2006, we redeemed all $250 million of our 8 3/8% Senior Subordinated Notes due 2012. The redemption included a premium related to early extinguishment of the Notes of $19 million and a charge of $8 million related to the remaining unamortized original issuance costs of these Notes. In the first six months of 2006, we recorded a $32 million benefit related to our business interruption insurance coverage as a result of the operations disruptions caused by the 2005 hurricanes.

International Operations. Our international operating expenses for the first six months of 2006 increased 40% primarily due to increased production and other taxes, which increased as a result of significantly higher crude oil prices. The 102% increase, stated on an Mcfe basis, resulted from the 31% decrease in production for the first six months of 2006 due to the timing of liftings in Malaysia.

Interest Expense. The following table presents information about our interest expense for the three and six month periods ended June 30, 2006 compared to the same periods of the prior year.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In millions)			
Gross interest expense	$ 24	$ 19	$ 42	$ 37
Capitalized interest	(10)	(11)	(22)	(23)
Total interest expense	$ 14	$ 8	$ 20	$ 14

The increase in interest expense for the three and six months ended June 30, 2006 resulted from the issuance of $550 million principal amount of our 6 5/8% Senior Subordinated Notes due 2016 on April 3, 2006 partially offset by the redemption of all $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012 on May 3, 2006.

Commodity Derivative Income (Expense). The following table presents information about the components of commodity derivative income (expense) for the three and six month periods ended June 30, 2006 compared to the same periods of the prior year.

	Three Months Ended June 30,		Six Months Ended June 30	
	2006	2005	2006	2005
	(In millions)			
Cash Flow Hedges:				
Hedge ineffectiveness	$ 1	$ 3	$ 6	$ (6)
Other Derivative Contracts:				
Unrealized gain (loss) due to changes in fair market value	9	(48)	11	(146)
Realized gain (loss) on settlement	36	(1)	35	(3)
Total commodity derivative income (expense)	$ 46	$ (46)	$ 52	$ (155)

Hedge ineffectiveness is associated with our hedging contracts that are designated for hedge accounting under SFAS No. 133. The unrealized gain (loss) due to changes in fair market value is associated with our derivative contracts that are not designated for hedge accounting and represents changes in the fair value of our open contracts during the period.

Taxes. The effective tax rates for the second quarter of 2006 and 2005 were 36.1% and 36.2%, respectively. The effective tax rates for the first six months of 2006 and 2005 were 36.1% and 33.2%, respectively. The effective tax rate for the first six months of 2005 was less than the federal statutory rate because the $8 million valuation allowance on our U.K. net operating loss carryforwards was reversed because of a substantial increase in estimated future taxable income as result of our Grove discovery in the U.K. North Sea. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing and amount of future production and future operating expenses and capital costs.

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow production and cash flow. We add new reserves and grow production through successful exploration and development drilling and the acquisition of properties. These activities require substantial capital expenditures. Historically, we have successfully grown our reserve base and production, resulting in net long-term growth in our cash flow from operating activities. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities.

We establish a capital budget at the beginning of each calendar year based on expected cash flow from operations for that year. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. Because of the nature of the properties we own, a substantial majority of our capital budget is discretionary. Our 2006 capital budget exceeds currently expected cash flow from operations by approximately $500 million. We will make up the shortfall with the remaining proceeds from our $550 million Senior Subordinated Notes offering (see *Cash Flows from Financing Activities* below) and borrowings under our credit arrangements.

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Credit Arrangements. In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of our credit facility provide for initial loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments under our credit facility may be increased to a maximum aggregate amount of $1.5 billion if the lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under our credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of prime rate or the weighted average of the rates on overnight federal funds transactions during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate (LIBOR), plus a margin that is based on a grid of our debt rating (100 basis points per annum at June 30, 2006). At July 26, 2006, we had no outstanding borrowings under our credit facility.

Our credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonment expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; and as long as our debt rating is below investment grade, the maintenance of an annual ratio of the calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At June 30, 2006, we were in compliance with all of our debt covenants.

As of July 26, 2006, we had $62 million of undrawn letters of credit under our credit facility. The letters of credit outstanding under the credit facility are subject to annual fees, based on a grid of our debt rating (87.5 basis points at July 26, 2006) plus an issuance fee of 12.5 basis points.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At July 26, 2006, we had no outstanding borrowings under our money market lines.

As of July 26, 2006, we had approximately $986 million of available borrowing capacity under our credit arrangements.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements. Generally, we use excess cash to pay down borrowings under our credit arrangements. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. We had a working capital deficit of $7 million as of June 30, 2006. This compares to a working capital deficit of $130 million as of December 31, 2005. Our current assets at June 30, 2006 include cash and short-term investments of $205 million that represent the remaining proceeds from our $550 million Senior Subordinated Note Offering in April 2006. Our working capital is affected by fluctuations in the fair value of our commodity derivative instruments. As of June 30, 2006, we had a net short-term derivative liability of $14 million compared to a net short-term derivative liability of $89 million at December 31, 2005.

Cash Flows from Operations. Cash flows from operations is primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts. Our cash flows from operations also are impacted by changes in working capital. We sell substantially all of our natural gas and oil production under floating market contracts. However, we enter into commodity hedging arrangements to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. See Oil and Gas Hedging below. We typically receive the cash associated with accrued oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations is impacted by changes in working capital and is not affected by DD&A, writedowns or other non cash charges.

Our net cash flow from operations was $692 million for the six months ended June 30, 2006, a 12% increase over the same period of the prior year. The increase was due to a 12% increase in our realized oil and gas prices (on a natural gas equivalent basis) and a decrease in working capital requirements during the six months ended June 30, 2006.

Capital Expenditures. Our first six months of 2006 capital spending was $850 million, an increase of 66% from our $512 million in capital spending during the same period of 2005. This excludes asset retirement obligations, which were $2 million during the first six months of 2006 and totaled $5 million during the same period of 2005. Of the $850 million, we invested $466 million in domestic development, $201 million in domestic exploration, $56 million in other domestic leasehold activity and $127 million internationally.

Our current budget for capital spending in 2006 is $1.9 billion, excluding approximately $180 million in hurricane repairs (a significant portion of the repairs are covered by insurance). The total includes $1.8 billion for capital projects and $108 million for capitalized interest and overhead. Approximately 25% of the amount related to capital projects is allocated to the Gulf of Mexico (including the traditional shelf, the deep and ultra-deep shelf and deepwater), 19% to the onshore Gulf Coast, 29% to the Mid-Continent, 8% to the Rocky Mountains and 19% to international projects. Actual levels of capital expenditures may vary significantly due to many factors, including the extent to which proved properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services. We continue to pursue attractive acquisition opportunities; however, the timing, size and purchase price of acquisitions are unpredictable. Historically, we have completed several acquisitions of varying sizes each year. Depending on the timing of an acquisition, we may spend additional capital during the year of the acquisition for drilling and development activities on the acquired properties.

Cash Flows from Financing Activities. Net cash flow provided by financing activities for the first half of 2006 was $307 million compared to $100 million of net cash flow used in financing activities for the same period of 2005.

In April 2006, we issued $550 million aggregate principal amount of our 6 5/8% Senior Subordinated Notes due 2016. In May 2006, we used the proceeds from the offering to redeem our $250 million principal amount 8 3/8% Senior Subordinated Notes due 2012. In addition, during the first half of 2006, we borrowed and repaid $342 million under our credit arrangements and received proceeds of $8 million from the issuance of shares of our common stock.

During the first half of 2005, we repaid a net $120 million under our credit arrangements and received proceeds of $20 million from the issuance of shares of our common stock.

Oil and Gas Hedging

We generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months as part of our risk management program. In the case of acquisitions, we may hedge acquired production for a longer period. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions.

While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically all of our hedged natural gas and crude oil production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges. Therefore we believe that our production in these locations is not subject to material basis risk. Nonetheless, due to current high levels of natural gas in storage and out of concern regarding significant variances in the basis differential for certain of our production in areas that are farther removed from the Henry Hub, we have hedged a portion of this basis risk for the period August through December 2006. The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.40 $0.60 less per MMBtu than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average $0.70 $0.80 less per MMBtu than the Henry Hub Index. The price we receive for our Gulf Coast oil production typically averages about $2 per barrel below the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is now averaging about $9 per barrel below the WTI price. Oil production from the Mid-Continent typically sells at a $1.00 $1.50 per barrel discount to WTI. Oil production from Malaysia typically sells at Tapis, or about even with WTI.

Please see the discussion and tables in Note 7, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing earlier in this report for a description of the accounting applicable to the derivative contracts utilized in our hedging program and a listing and fair value of those open contracts as of June 30, 2006.

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New Accounting Developments

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FAS 109* (Interpretation No. 48). Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes* . Interpretation No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Interpretation No. 48 is effective for fiscal years beginning after December 15, 2006. Earlier application is encouraged if the company has not yet issued financial statements, including interim financial statements, in the period Interpretation No. 48 is adopted. We are reviewing the Interpretation and analyzing the potential impact, in any, of this new guidance.

General Information

General information about us can be found at www.newfield.com. In conjunction with our web page, we also maintain an electronic publication entitled @NFX. @NFX is periodically published to provide updates on our operating activities and our latest publicly announced estimates of expected production volumes, costs and expenses for the then current quarter. Recent editions of @NFX are available on our web page. To receive @NFX directly by email, please forward your email address to info@newfld.com or visit our web page and sign up. Unless specifically incorporated, the information about us at www.newfield.com or in any edition of @NFX is not part of this report.

Our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results such as planned capital expenditures, the availability of capital resources to fund capital expenditures, production targets, anticipated production rates, our financing plans and our business strategy and other plans and objectives for future operations. Although we believe that the expectations reflected in this information are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties. Actual results may vary significantly from those anticipated due to many factors, including:

- drilling results;
- oil and gas prices;
- well and waterflood performance;
- severe weather conditions (such as hurricanes);
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- the availability of refining capacity for the crude oil we produce from our Monument Butte field in Utah; and
- the availability of capital resources.

All written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by such factors.

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Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf gas to one Bbl of crude oil or condensate.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

NYMEX. The New York Mercantile Exchange.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in oil and gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-24 months as part of our risk management program. In the case of acquisitions, we may hedge acquired production for a longer period. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. For a further discussion of our hedging activities, see the information under the caption Oil and Gas Hedging in Item 2 of this report.

Please see the discussion and tables in Note 7, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing earlier in this report for a description of the accounting applicable to the derivative contracts utilized in our hedging program and a listing and fair value of those open contracts as of June 30, 2006.

Interest Rates

At June 30, 2006, our long-term debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$
7.45% Senior Notes due 2007[(1)]	75	50
7 5/8% Senior Notes due 2011[(1)]	125	50
6 5/8% Senior Subordinated Notes due 2014	325	
6 5/8% Senior Subordinated Notes due 2016	550	
Total long-term debt	$ 1,075	$ 100

(1) $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 7 5/8% Senior Notes due 2011 are subject to interest rate swaps. These swaps provide for us to pay variable and receive fixed

interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes.

We consider our interest rate exposure to be minimal because a substantial majority, about 91% of our long-term debt obligations, after taking into account our interest rate swap agreements, were at fixed rates.

Foreign Currency Exchange Rates

The British pound is the functional currency for our operations in the United Kingdom. The functional currency for all other foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at June 30, 2006.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2006 in ensuring that material information was accumulated and communicated to management, and made known to our Chief Executive Officer and Chief Financial Officer, on a timely basis to allow disclosure as required in this report.

Changes in Internal Control Over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, to determine whether any changes occurred during the second quarter of 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II

Item 1. Legal Proceedings

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

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

The following table sets forth certain information with respect to repurchases of our common stock during the six months ended June 30, 2006:

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under The Plans or Programs
January 1 January 31, 2006				
February 1 February 28, 2006	60,716	$ 51.27		
March 1 March 31, 2006				
April 1 April 30, 2006	199	41.71		
May 1 May 31, 2006	106	47.05		
June 1 June 30, 2006	265	43.06		

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly

announced
program to
repurchase
shares of our
common stock.

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

At the May 4, 2006 Annual Meeting of Stockholders, our stockholders voted on four matters. As of the March 7, 2006 record date, 128,515,319 shares of common stock were outstanding and entitled to vote at the meeting.

(1) Election of Thirteen Directors:

Our stockholders elected the thirteen nominees for director by the following vote:

Nominee Elected	For	Withheld
David A. Trice	123,272,921	3,019,278
David F. Schaible	123,818,562	2,473,637
Howard H. Newman	121,236,671	5,055,528
Thomas G. Ricks	123,645,658	2,646,541
Dennis R. Hendrix	125,574,736	717,463
C. E. (Chuck) Shultz	123,308,726	2,983,473
Philip J. Burguieres	126,008,412	283,787
John Randolph Kemp III	125,624,237	667,962
J. Michael Lacey	125,641,446	650,753
Joseph H. Netherland	125,400,489	891,710
J. Terry Strange	121,917,545	4,374,654
Pamela J. Gardner	125,954,221	337,978
Juanita F. Romans	126,032,656	259,543

(2) Approval of First Amendment to Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan:

Our stockholders approved the First Amendment to Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan by the following vote:

For	Against	Abstentions and Broker Non-Votes
86,296,698	12,200,988	27,794,513

(3) Approval of Second Amendment to Newfield Exploration Company 2001 Employee Stock Purchase Plan:

Our stockholders approved the Second Amendment to Newfield Exploration Company 2001 Employee Stock Purchase Plan by the following vote:

For	Against	Abstentions and Broker Non-Votes
91,688,266	6,897,738	27,706,195

(4) Ratification of Appointment of Independent Public Accountants:

Our stockholders ratified the appointment of PricewaterhouseCoopers LLP as our independent accountants for 2006 by the following vote:

For	Against	Abstentions and Broker Non-Votes
125,731,835	496,086	64,278

Item 6. Exhibits

(a) Exhibits:

Exhibit Number	Description
31.1	Certification of Chief Executive Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURE

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.

	NEWFIELD EXPLORATION COMPANY
Date: July 28, 2006	By: /s/ TERRY W. RATHERT
	Terry W. Rathert Senior Vice President and Chief Financial Officer

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