NEWFIELD EXPLORATION CO /DE/
Form 10-Q
April 27, 2007

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UNITED STATES
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 March 31, 2007

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 o

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

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

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

Yes o No þ

As of April 26, 2007, there were 129,984,848 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)

	March 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 26	$ 80
Short-term investments		10
Accounts receivable	381	378
Inventories	58	44
Derivative assets	89	280
Deferred taxes	14	
Other current assets	40	59
Total current assets	608	851
Oil and gas properties (full cost method, of which $1,074 at March 31, 2007 and $1,002 at December 31, 2006 were excluded from amortization)	9,346	8,890
Less accumulated depreciation, depletion and amortization	(3,413)	(3,235)
	5,933	5,655
Furniture, fixtures and equipment, net	33	28
Derivative assets	3	19
Other assets	20	20
Goodwill	62	62
Total assets	$ 6,659	$ 6,635
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 91	$ 59
Current debt	124	124
Accrued liabilities	607	667
Advances from joint owners	60	90
Asset retirement obligation	36	40
Derivative liabilities	130	80
Deferred taxes		63
Total current liabilities	1,048	1,123
Other liabilities	49	28

Derivative liabilities	167	179
Long-term debt	1,175	1,048
Asset retirement obligation	239	232
Deferred taxes	1,003	963
Total long-term liabilities	2,633	2,450
Commitments and contingencies (Note 5)		
Stockholders equity:		
Preferred stock ($0.01 par value; 5,000,000 shares authorized; no shares issued)		
Common stock ($0.01 par value; 200,000,000 shares authorized at March 31, 2007 and December 31, 2006; 131,830,758 and 131,063,555 shares issued and outstanding at March 31, 2007 and December 31, 2006, respectively)	1	1
Additional paid-in capital	1,209	1,198
Treasury stock (at cost; 1,887,142 and 1,879,874 shares at March 31, 2007 and December 31, 2006, respectively)	(31)	(30)
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustment	15	14
Commodity derivatives	(4)	(5)
Minimum pension liability	(3)	(3)
Retained earnings	1,791	1,887
Total stockholders equity	2,978	3,062
Total liabilities and stockholders equity	$ 6,659	$ 6,635

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 March 31, 2007	Three Months Ended March 31, 2006
Oil and gas revenues	$ 440	$ 431
Operating expenses:		
Lease operating	112	52
Production and other taxes	18	16
Depreciation, depletion and amortization	180	131
General and administrative	39	30
Ceiling test writedown	47	
Other		(30)
Total operating expenses	396	199
Income from operations	44	232
Other income (expenses):		
Interest expense	(23)	(18)
Capitalized interest	11	12
Commodity derivative income (expense)	(158)	6
Other	1	1
	(169)	1
Income (loss) before income taxes	(125)	233
Income tax provision (benefit):		
Current	9	11
Deferred	(38)	73
	(29)	84
Net income (loss)	$ (96)	$ 149
Earnings (loss) per share:		
Basic	$ (0.75)	$ 1.18
Diluted	$ (0.75)	$ 1.17

Weighted average number of shares outstanding for basic earnings (loss) per share	127	126
Weighted average number of shares outstanding for diluted earnings (loss) per share	127	128

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)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Cash flows from operating activities:		
Net income (loss)	$ (96)	$ 149
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	180	131
Deferred taxes	(38)	73
Stock-based compensation	4	7
Commodity derivative (income) expense	249	(8)
Ceiling test writedown	47	
Changes in operating assets and liabilities:		
Decrease in accounts receivable	2	41
Increase in inventories	(14)	(7)
Decrease in other current assets	18	5
Decrease in accounts payable and accrued liabilities	(7)	(45)
Decrease in commodity derivative liabilities	(1)	(16)
Increase (decrease) in advances from joint owners	(30)	9
Increase in other liabilities	21	1
Net cash provided by operating activities	335	340
Cash flows from investing activities:		
Additions to oil and gas properties	(539)	(337)
Proceeds from sale of oil and gas properties	1	
Additions to furniture, fixtures and equipment	(6)	(2)
Redemption of short-term investments	24	
Net cash used in investing activities	(520)	(339)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	453	229
Repayments of borrowings under credit arrangements	(326)	(229)
Proceeds from issuances of common stock	3	2
Stock-based compensation excess tax benefit	1	1
Purchases of treasury stock		(3)
Net cash provided by financing activities	131	

Effect of exchange rate changes on cash and cash equivalents		1
Increase (decrease) in cash and cash equivalents	(54)	2
Cash and cash equivalents, beginning of period	80	39
Cash and cash equivalents, end of period	$ 26	$ 41

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	Retained	Accumulated Other Comprehensive Income	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Earnings	(Loss)	Equity
Balance, December 31, 2006	131.1	$ 1	(1.9)	$ (30)	$ 1,198	$ 1,887	$ 6	$ 3,062
Issuance of common and restricted stock	0.8				3			3
Stock-based compensation					7			7
Treasury stock, at cost				(1)				(1)
Stock-based compensation excess tax benefit					1			1
Comprehensive income (loss):								
Net loss						(96)		(96)
Foreign currency translation adjustment, net of tax of ($0)							1	1
Reclassification adjustments for settled hedging positions, net of tax of $0							(1)	(1)
Changes in fair value of outstanding hedging positions, net of tax of ($1)							2	2
Total comprehensive income (loss)								(94)
Balance, March 31, 2007	131.9	$ 1	(1.9)	$ (31)	$ 1,209	$ 1,791	$ 8	$ 2,978

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 diversified domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the onshore Gulf Coast, 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 Newfield, 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, 2006.

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 there can be no assurance that oil and gas prices will not 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 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 based on our proved oil and gas reserves.

Investments

Investments consist of highly liquid investment grade commercial paper and municipal and corporate bonds with a maturity of less than one year. 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.

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 in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into floating production, storage and off-loading vessels and sold periodically as barge quantities are accumulated. The product inventory at March 31, 2007 consisted of approximately 177,000 barrels of crude oil valued at cost of $7 million. 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 income (expense) 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 assuming the normal operation of the asset, 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 changes to our ARO for the three months ended March 31, 2007 are set forth below (in millions):

Balance as of January 1, 2007	$ 272
Accretion expense	3
Additions	
Revisions	14
Settlements	(14)
Balance of ARO as of March 31, 2007	$ 275

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123 (revised 2004) (SFAS No. 123 (R)), *Share-Based Payment*, 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, has been or 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, has been or 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. See Note 11, Stock-Based Compensation, for a full discussion of our stock-based compensation.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of SFAS 109, Accounting for Income Taxes. FIN 48 prescribes a comprehensive model for how companies should recognize, measure, present and disclose in their financial statements uncertain tax positions taken or expected to be taken on a tax return. Under FIN 48, tax positions are recognized in our consolidated financial statements as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with tax authorities assuming full knowledge of the position and all relevant facts. These amounts are subsequently reevaluated and changes are recognized as adjustments to current period tax expense. FIN 48 also revised disclosure requirements to include an annual tabular rollforward of unrecognized tax benefits.

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the adoption, we recognized no material adjustment in our tax liability for unrecognized income tax benefits. At the adoption date of January 1, 2007, we had approximately $0.4 million of unrecognized tax benefits, all of which would affect our effective tax rate if recognized. At March 31, 2007, the unrecognized tax benefit amount was unchanged from adoption.

If applicable, we would recognize interest and penalties related to uncertain tax positions in interest expense. As of March 31, 2007, we have not accrued interest related to uncertain tax positions due to overpayments.

The tax years 2003-2006 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

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 shares (using the treasury stock method). See Note 11, Stock-Based Compensation.

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

	Three Months Ended March 31,	
	2007	**2006**
	(In millions, except per share data)	
Income (loss) (numerator):		
Net income (loss) basic	$ (96)	$ 149
Net income (loss) diluted	$ (96)	$ 149
Weighted average shares (denominator):		
Weighted average shares basic	127	126
Dilution effect of stock options and unvested restricted shares outstanding at end of period [(1)]	-	2
Weighted average shares diluted	127	128
Earnings (loss) per share:		
Basic	$ (0.75)	$ 1.18

Diluted	$ (0.75)	$ 1.17

(1) For the three months ended March 31, 2007, the effect of outstanding employee stock options and unvested restricted shares is antidilutive to earnings per share and is ignored in the computation of the diluted earnings per share for the period.

There were no antidilutive stock options outstanding for the three month period ended March 31, 2006.

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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:

	March 31, 2007	December 31, 2006
	(In millions)	
Subject to amortization	$ 8,272	$ 7,888
Not subject to amortization:		
Exploration wells in progress	245	182
Development wells in progress	65	49
Capitalized interest	99	94
Fee mineral interests	23	23
Other capital costs:		
Incurred in 2007	24	
Incurred in 2006	97	102
Incurred in 2005	83	92
Incurred in 2004 and prior	438	460
Total not subject to amortization	1,074	1,002
Gross oil and gas properties	9,346	8,890
Accumulated depreciation, depletion and amortization	(3,413)	(3,235)
Net oil and gas properties	$ 5,933	$ 5,655

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 (100,000 acres), evaluation of the Monument Butte Field in its entirety will take significantly longer than four years. At March 31, 2007 and December 31, 2006, $287 million and $292 million, respectively, of costs associated with the Monument Butte Field were not subject to amortization.

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis.

Capitalized costs and estimated future development and retirement costs are amortized on a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. A particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using end of period oil and gas prices applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting); plus
- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less
- related income tax effects.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the sale involves a significant quantity of reserves in relation to the cost center, in which case a gain or loss is recognized.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown would reduce earnings and stockholders equity in the period of occurrence and result in lower depreciation, depletion and amortization expense in future periods.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At March 31, 2007, the cost center ceiling for our U.K. oil and gas properties was calculated based upon quoted market prices of $3.74 per Mcf for gas and $55.38 per Bbl for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our U.K. cost pool exceeded the full cost ceiling, resulting in a ceiling test writedown of $47 million in the first quarter of 2007.

4. Debt:

As of the indicated dates, our debt consisted of the following:

	March 31, 2007	December 31, 2006
	(In millions)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans	95	
Total bank revolving credit facility	95	
Money market line of credit (1)	32	
Total credit arrangements	127	
$125 million 7.45% Senior Notes due 2007 (2)	125	125
Fair value of interest rate swaps (2) (3)	(1)	(1)
$175 million 7 5/8% Senior Notes due 2011	175	175
Fair value of interest rate swaps (3)	(2)	(2)
Total senior unsecured notes	297	297
Total senior unsecured debt	424	297
$325 million 6 5/8% Senior Subordinated Notes due 2014	325	325
$550 million 6 5/8% Senior Subordinated Notes due 2016	550	550
Total debt	1,299	1,172
Less: Current potion of debt (2)	124	124
Total long-term debt	$ 1,175	$ 1,048

(1) Because capacity under our credit

facility was available to repay borrowings under our money market lines of credit as of the indicated dates, these obligations were classified as long-term.

(2) Due October 2007.

(3) We have hedged $50 million principal amount of our $125 million 7.45% Senior Notes due 2007 and $50 million principal amount of our $175 million 7 5/8% Senior Notes due 2011. The hedges provide for us to pay variable and receive fixed interest payments.

Credit Arrangements

In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of the credit facility provide for initial loan commitments of $1 billion from a syndication 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 the credit facility. Loans under the credit facility bear interest, at our option, 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, plus a margin that is based on a grid of our debt rating (100 basis points per annum at March 31, 2007). At March 31, 2007, we had $95 million outstanding under the credit facility.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Under our credit facility, we pay commitment fees on the undrawn amounts based on a grid of our debt rating (0.20% per annum at March 31, 2007). We incurred fees under these arrangements of approximately $0.7 million for the three months ended March 31, 2007.

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, and other noncash charges and expenses including unrealized gains and losses on commodity derivatives 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 March 31, 2007, we were in compliance with all of our debt covenants.

As of March 31, 2007, we had $51 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 March 31, 2007), plus an issuance fee of 12.5 basis points.

We also have a total of $90 million of borrowing capacity under money market lines of credit with various banks. At March 31, 2007, we had $32 million outstanding under our money market lines.

5. Commitments and Contingencies:

In December 2002, a lawsuit against our Mid-Continent subsidiary was filed in Beaver County, Oklahoma and was later certified as a class action royalty owner lawsuit. The complaint alleges that we improperly reduced royalty payments for certain expenses and charges, and also claims breach of contract and breach of fiduciary duties, among other claims. In April 2007, we entered into a non-binding settlement agreement, subject to final documentation and court approval, with respect to the lawsuit. In the first quarter of 2007, we increased our litigation settlement reserve for the lawsuit, which resulted in a charge to earnings that was recorded under the caption General and administrative on our consolidated income statement.

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

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 months ended March 31, 2007 and 2006. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

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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 March 31, 2007:						
Oil and gas revenues	$ 419	$	$ 12	$ 9	$	$ 440
Operating expenses:						
Lease operating	106	1	4	1		112
Production and other taxes	15		3			18
Depreciation, depletion and amortization.	174		3	3		180
General and administrative	38			1		39
Ceiling test writedown		47				47
Allocated income taxes	31		1	2		
Net income (loss) from oil and gas properties	$ 55	$ (48)	$ 1	$ 2	$	
Total operating expenses						396
Income from operations						44
Interest expense, net of interest income, capitalized interest and other						(11)
Commodity derivative expense						(158)
Loss before income taxes						$ (125)
Total long-lived assets	$ 5,480	$ 184	$ 204	$ 65	$	$ 5,933
Additions to long-lived assets	$ 462	$ 30	$ 25	$ 4	$	$ 521

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			

Three Months Ended March 31, 2006:						
Oil and gas revenues	$ 423	$	$ 8	$	$	$ 431
Operating expenses:						
Lease operating	50		2			52
Production and other taxes	15		1			16
Depreciation, depletion and amortization.	130		1			131
General and administrative	27	2	1			30
Other	(30)					(30)
Allocated income taxes	81	(1)	1			
Net income (loss) from oil and gas properties	$ 150	$ (1)	$ 2	$	$	
Total operating expenses						199
Income from operations						232
Interest expense, net of interest income, capitalized interest and other						(5)
Commodity derivative income						6
Income before income taxes						$ 233
Total long-lived assets	$ 4,429	$ 88	$ 100	$ 50	$ 6	$ 4,673
Additions to long-lived assets	$ 328	$ 42	$ 15	$ 5	$	$ 390

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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. 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. At March 31, 2007, we had a net $4 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 the entire net loss to be sold within the next 12 months. 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.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At March 31, 2007, we had outstanding contracts that qualified and were designated as cash flow hedges with respect to our future production as follows:

Oil

		NYMEX Contract Price Per Bbl					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	Volume in MBbls	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	(Liability) (In millions)
April 2007 June 2007							
Price swap contracts	211	$ 41.77					$ (5)
Collar contracts	91		$ 50.00 - $55.00	$ 52.50	$ 77.10 - $83.25	$ 80.18	
July 2007 September 2007							
Price swap contracts	92	61.25					(1)
Collar contracts	92		50.00 - 55.00	52.50	77.10 - 83.25	80.18	
October 2007 December 2007							
Price swap contracts	92	61.25					(1)
Collar contracts	92		50.00 - 55.00	52.50	77.10 - 83.25	80.18	
							$ (7)

Other Derivative Contracts

In the fourth quarter of 2005, we elected not to designate any additional swap, collar and floor contracts that were entered into subsequent to September 30, 2005 as accounting hedges under SFAS No. 133. These contracts, as well as our three-way contracts that 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.

At March 31, 2007, we had outstanding contracts with respect to our future production that were not accounted for as hedges as set forth in the tables below.

Natural Gas

		NYMEX Contract Price per MMBtu					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	(Liability) (In millions)
April 2007 June 2007							
Price swap contracts	25,800	$ 8.81					$ 29
Collar contracts	19,100		$ 6.50 - $8.00	$ 6.90	$ 8.23 - $10.15	$ 8.81	

July 2007 September 2007							
Price swap contracts	25,500	8.87					19
Collar contracts	15,350		6.50 - 8.00	6.86	8.23 - 10.15	8.80	(4)
October 2007 December 2007							
Price swap contracts	11,420	8.98					5
Collar contracts	19,695		6.50 - 8.00	7.73	8.23 - 12.40	10.51	(5)
January 2008 March 2008							
Price swap contracts	4,550	9.23					(2)
Collar contracts	22,595		8.00	8.00	10.00 - 12.40	11.04	(16)
April 2008 June 2008							
Price swap contracts	4,095	7.85					(1)
Collar contracts	1,365		7.00	7.00	9.70	9.70	
July 2008 September 2008							
Price swap contracts	4,140	7.85					(1)
Collar contracts	1,380		7.00	7.00	9.70	9.70	
October 2008							
Price swap contracts	1,395	7.85					(1)
Collar contracts	465		7.00	7.00	9.70	9.70	
							$ 23

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil

		NYMEX Contract Price per Bbl							Estimat Fair Value Asset
					Collars				
	Volume in	Swaps (Weighted	Additional Put		Floors		Ceilings		(Liabili (In
eriod and Type of Contract	MBbls	Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	million
pril 2007 June 2007									
rice swap contracts	30	$ 70.00							$
ollar contracts	60				$ 60.00	$ 60.00	$ 80.50 - $81.00	$ 80.75	(1
-Way collar contracts	879		$ 25.00 - $50.00	$ 30.02	32.00 - 60.00	37.12	44.70 - 82.00	55.33	(12
ly 2007 September 2007									
rice swap contracts	30	70.00							
ollar contracts	60				60.00	60.00	80.50 - 81.00	80.75	(1
-Way collar contracts	888		25.00 - 50.00	30.00	32.00 - 60.00	37.10	44.70 - 82.00	55.31	(13
ctober 2007 December 2007									
rice swap contracts	30	70.00							
ollar contracts	60				60.00	60.00	80.50 - 81.00	80.75	(1
-Way collar contracts	888		25.00 - 50.00	30.00	32.00 - 60.00	37.10	44.70 - 82.00	55.31	(14
nuary 2008 March 2008									
-Way collar contracts	819		25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	(16
pril 2008 June 2008									
-Way collar contracts	819		25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	(16
ly 2008 September 2008									
-Way collar contracts	828		25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	(16
ctober 2008 December 2008									
-Way collar contracts	828		25.00 - 29.00	26.56	32.00 - 35.00	33.00	49.50 - 52.90	50.29	(16
nuary 2009 December 2009									
-Way collar contracts	3,285		25.00 - 30.00	27.00	32.00 - 36.00	33.33	50.00 - 54.55	50.62	(57
nuary 2010 December 2010									
-Way collar contracts	3,645		25.00 - 32.00	28.60	32.00 - 38.00	34.90	50.00 - 53.50	51.52	(55
									$ (218

Commodity Derivative Income (Expense)

The following table presents information about the components of commodity derivative income (expense) for the indicated period.

	Three Months Ended March 31, 2007	2006
	(In millions)	
Cash flow hedges:		
Hedge ineffectiveness	$	$ 5

Other derivative contracts:		
Unrealized gain (loss) due to changes in fair market value	(246)	2
Realized gain (loss) on settlement	88	(1)
Total commodity derivative income (expense)	$ (158)	$ 6

8. Accrued Liabilities:

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

	March 31, 2007	December 31, 2006
	(In millions)	
Revenue payable	$ 103	$ 95
Accrued capital costs	338	349
Accrued lease operating expenses	45	58
Employee incentive expense	32	63
Accrued interest on notes	24	21
Taxes payable	22	21
Deferred acquisition payments	9	9
Insurance premium payable	12	16
Other	22	35
Total accrued liabilities	$ 607	$ 667

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Accounts Receivable:

As of the indicated dates, our accounts receivable consisted of the following:

	March 31, 2007	December 31, 2006
	(In millions)	
Revenue	$ 218	$ 201
Joint interest	153	148
Receivable from broker		14
MMS deposits	7	8
Texas severance tax	4	6
Other	(1)	1
Total accounts receivable	$ 381	$ 378

10. Comprehensive Income:

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

	Three Months Ended March 31, 2007	2006
	(In millions)	
Net income (loss)	$ (96)	$ 149
Foreign currency translation adjustment, net of tax of ($0)	1	
Reclassification adjustments for settled hedging positions, net of tax of $0 and $9, respectively	(1)	(16)
Changes in fair value of outstanding hedging positions, net of tax of ($1) and ($8), respectively	2	15
Total comprehensive income (loss)	$ (94)	$ 148

11. Stock-Based Compensation:

On January 1, 2006, we adopted 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, has been or 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, has been or 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.

Historically, we have used and we anticipate continuing to use unissued shares of stock when stock options are exercised. At March 31, 2007, we had approximately 1.2 million additional shares available for issuance pursuant to our existing employee and director plans. Of the shares available at March 31, 2007, only 0.4 million could be granted as restricted shares. Grants of restricted shares under our 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of restricted shares issued.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the three months ended March 31, 2007, we recorded stock-based compensation expense of $5 million (pre-tax) for all plans. Of this amount, $1 million was capitalized in oil and gas properties. For the three months ended March 31, 2007, we reported $1 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

As of March 31, 2007, we had approximately $76 million of total unrecognized compensation expense related to unvested stock-based compensation plans. This compensation expense is expected to be recognized on a straight-line basis over the remaining vesting period of approximately 5 years.

Stock Options. We have granted stock options under several 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%, an expected life of 6.5 years and a weighted average volatility of 37.52%.

The following table provides information related to stock option activity for the three months ended March 31, 2007:

	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (In years)	Aggregate Intrinsic Value [(1)] (In millions)
Outstanding at December 31, 2006	5.6	$ 23.68	$ 10.71	6.3	$ 124
Granted					
Exercised	(0.2)	19.60	8.79		3
Forfeited	(0.1)	30.70	14.25		1
Outstanding at March 31, 2007	5.3	$ 23.72	$ 10.72	6.1	$ 96
Exercisable at March 31, 2007	3.2	$ 20.66	$ 9.28	5.3	$ 67

(1) The intrinsic value of a stock option is the amount by which the current market value of our common stock at the indicated date, or at the time of grant, exercise or

forfeiture, as applicable, exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during the three month period ended March 31, 2006 was approximately $2 million.

The following table summarizes information about stock options outstanding and exercisable at March 31, 2007:

	Options Outstanding			**Options Exercisable**	
Range of Exercise Prices	**Number of Shares Underlying Options (In thousands)**	**Weighted Average Remaining Contractual Life (In years)**	**Weighted Average Exercise Price per Share**	**Number of Shares Underlying Options (In thousands)**	**Weighted Average Exercise Price per Share**
$7.97 to $10.00	42	1.4	$ 8.06	42	$ 8.06
10.01 to 12.50	90	1.0	11.76	90	11.76
12.51 to 15.00	451	2.9	14.72	446	14.72
15.01 to 17.50	1,119	5.3	16.62	914	16.64
17.51 to 22.50	836	5.0	18.95	625	18.95
22.51 to 27.50	882	6.9	24.73	427	24.57
27.51 to 35.00	1,585	7.7	31.16	555	31.25
35.01 to 41.72	357	8.0	37.93	69	37.78
	5,362	6.1	$ 23.72	3,168	$ 20.66

On March 30, 2007, the last reported sales price of our common stock on the New York Stock Exchange was $41.71 per share.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Shares. At March 31, 2007, our employees held 1.1 million restricted shares that primarily vest over the service period of four to five years. The vesting of these shares is dependant upon the employees continued service with our company.

In addition, at March 31, 2007, our employees held 1.8 million restricted shares subject to performance-based vesting criteria (substantially all of which are considered market-based restricted shares under SFAS No. 123(R)). In February 2007, 293,338 of these restricted performance-based shares were granted. The number of these shares that vest is based upon established performance targets that will be assessed on March 1, 2010. The grant date fair value of these shares was $24.04 per share for a total value of $7 million. The expense will be recognized ratably over the service period from February 2007 to March 2010. The grants to our executive officers contain a retirement provision that permits them to retire on or after March 1, 2008, if certain other conditions are met, without forfeiting the shares granted. To the extent that our executive officers qualify under this provision, the expense will be recognized ratably over the service period from February 2007 to the applicable retirement eligibility date. 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 a year is subject to the achievement of the targets identified in the respective restricted share agreements.

Under our non-employee director restricted stock plan as in effect on March 31, 2007, immediately after each annual meeting of our stockholders, each of our non-employee directors then in office 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 the annual meeting. In addition, new non-employee 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 March 31, 2007, 109,913 shares remained available for grants under this plan.

The following table provides information related to restricted share activity for the three months ended March 31, 2007:

	Service-Based	Performance/ Market-Based	Total
	(In thousands, except per share data)		
Non-vested shares outstanding at December 31, 2006	649	1,516	2,165
Granted	453	293	746
Forfeited	(18)	(12)	(30)
Vested	(27)		(27)
Non-vested shares outstanding at March 31, 2007	1,057	1,797	2,854
Weighted average grant date fair value per share of shares granted during the period	$ 41.57	$ 24.04	$ 34.62
Total fair value of shares vested during the period	$ 522	$	$ 522

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 in the plan.

During the first quarter of 2007, options to purchase 29,481 shares of our common stock at a weighted average fair value of $11.90 per share were issued under the plan. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 5.09%, an expected life of 6 months and weighted-average volatility of 35.88%. At March 31, 2007, 658,614 shares of our common stock remained available for issuance under this plan.

U.K. Bonus Plans. We have cash bonus plans for employees of our U.K. North Sea operations. The amount of bonuses is determined based on the value of the shares of our U.K. subsidiary as determined by our Board of Directors. These plans are accounted for as liability plans under SFAS No. 123(R) and are not material to our financial statements.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Income Taxes:

The provision for income taxes for the indicated periods was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	Three Months Ended March 31,	
	2007	2006
	(In millions)	
Amount computed using the statutory rate	$ (44)	$ 81
Increase (decrease) in taxes resulting from:		
State and local income taxes, net of federal effect	1	3
Net effect of different tax rates in non-U.S. jurisdictions	(8)	
Tax credits and other	(2)	
Valuation allowance	24	
Total provision for income taxes	$ (29)	$ 84

As of March 31, 2007, we had NOL carryforwards for international income tax purposes of approximately $98 million that may be used in future years to offset taxable income. We currently estimate that we will not be able to utilize these international NOLs, therefore a valuation allowance was established for them. Utilization of NOL carryforwards is dependent upon generating sufficient taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in natural gas and oil prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

The rollforward of our deferred tax asset valuation allowance is as follows:

	Three Months Ended March 31,	
	2007	2006
	(In millions)	
Balance at the beginning of the period	$ (21)	$ (3)
Credited (charged) to provision for income taxes:		
United Kingdom NOL carryforwards	(24)	
Balance at the end of the period	$ (45)	$ (3)

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

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 Anadarko and Arkoma Basins of the Mid-Continent, the onshore Gulf Coast, 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 as part of our risk management program. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund capital programs and manage price risks and returns on some of our acquisitions and drilling programs.

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.

Accounting for Hedging Activities. Beginning October 1, 2005, we elected not to designate any future price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. Please see *Management s Discussion and Analysis of Financial Condition and Results of Operations* Critical Accounting Policies and Estimates *Commodity Derivative Activities* in Item 7 of our annual report on Form 10-K for the year ended December 31, 2006 and 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.

Other factors. Please see *Risk Factors* in Item 1A of our annual report on Form 10-K for the year ended December 31, 2006 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 includes the effects of the settlement of derivative contracts associated with our production that are accounted for as hedges. Settlement of derivative contracts that are not accounted for as hedges has no effect on our reported revenues.

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 first quarter of 2007 were 2% higher than the comparable period of 2006 due to higher oil and gas production offset by lower oil and gas prices.

	Three Months Ended March 31, 2007	2006	Percentage Increase (Decrease)
Production [(1)]:			
United States:			
Natural gas (Bcf)	51.8	44.4	17%
Oil and condensate (MBbls)	1,740	1,473	18%
Total (Bcfe)	62.3	53.2	17%
International:			
Natural gas (Bcf)			
Oil and condensate (MBbls)	404	115	251%
Total (Bcfe)	2.4	0.7	251%
Total:			
Natural gas (Bcf)	51.8	44.4	17%
Oil and condensate (MBbls)	2,144	1,588	35%
Total (Bcfe)	64.7	53.9	20%
Average Realized Prices [(2)]:			
United States:			
Natural gas (per Mcf)	$ 6.37	$ 7.79	(18%)
Oil and condensate (per Bbl)	49.62	51.17	(3%)
Natural gas equivalent (per Mcfe)	6.69	7.92	(16%)
International:			
Natural gas (per Mcf)	$	$	
Oil and condensate (per Bbl)	51.86	65.79	(21%)
Natural gas equivalent (per Mcfe)	8.64	10.97	(21%)
Total:			
Natural gas (per Mcf)	$ 6.37	$ 7.79	(18%)
Oil and condensate (per Bbl)	50.04	52.23	(4%)
Natural gas equivalent (per Mcfe)	6.76	7.96	(15%)

(1) Represents 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 $8.18 and $7.83 per Mcf for the first quarter of 2007 and 2006, respectively. Our total oil and condensate average realized price would have been $47.49 and $50.55 per Bbl for the first quarter of 2007 and 2006, respectively. Without the effects of any hedging contracts, our average realized prices for the first quarter of 2007 and 2006 would have been $6.37 and $7.64 per Mcf, respectively, for gas and $51.18 and $58.76 per Bbl, respectively, for oil.

Production. Our total oil and gas production (stated on a natural gas equivalent basis) for the first quarter of 2007 increased 20% over the comparable period of 2006. The first quarter 2007 increase was primarily due to successful drilling efforts in the Mid-Continent and the negative impact the approximately 8 Bcfe of Gulf of Mexico production deferrals related to the 2005 storms had on the first quarter of 2006.

Natural Gas. Our first quarter 2007 natural gas production increased 17% when compared to the same period of 2006. The first quarter 2007 increase was primarily due to successful drilling efforts in the Mid-Continent and the 2006 Gulf of Mexico production deferrals mentioned above.

Crude Oil and Condensate. Our first quarter 2007 oil and condensate production increased 35% compared to the same period of 2006. The increase was the result of the timing of liftings of production in Malaysia and China and the 2006 Gulf of Mexico production deferrals mentioned above.

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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 our 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 first quarter of 2007 and 2006.

	Unit-of-Production			Amount		
	Three Months Ended March 31,		Percentage Increase (Decrease)	Three Months Ended March 31,		Percentage Increase (Decrease)
	2007	2006		2007	2006	
	(Per Mcfe)			(In millions)		
United States:						
Lease operating	$ 1.70	$ 0.95	79%	$ 106	$ 50	110%
Production and other taxes	0.23	0.28	(18%)	15	15	(3%)
Depreciation, depletion and amortization	2.79	2.44	14%	174	130	34%
General and administrative	0.61	0.51	20%	38	27	40%
Other		(0.56)	(100%)		(30)	(100%)
Total operating expenses	$ 5.34	$ 3.62	48%	$ 333	$ 192	73%
International:						
Lease operating	$ 2.58	$ 2.67	(3%)	$ 6	$ 2	240%
Production and other taxes	1.26	1.19	6%	3	1	270%
Depreciation, depletion and amortization	2.53	1.73	46%	6	1	414%
General and administrative	0.37	3.19	(88%)	1	3	(59%)
Ceiling test writedown	19.32		100%	47		100%
Total operating expenses	$ 26.06	$ 8.78	197%	$ 63	$ 7	942%
Total:						
Lease operating	$ 1.73	$ 0.97	78%	$ 112	$ 52	114%
Production and other taxes	0.27	0.29	(7%)	18	16	11%
Depreciation, depletion and amortization	2.78	2.43	14%	180	131	37%
General and administrative	0.60	0.55	9%	39	30	32%
Ceiling test writedown	0.72		100%	47		100%
Other		(0.56)	(100%)		(30)	(100%)
Total operating expenses	$ 6.11	$ 3.68	66%	$ 396	$ 199	99%

Domestic Operations. Our domestic operating expenses for the first quarter of 2007, stated on an Mcfe basis, increased 48% over the same period of 2006. This increase was primarily related to the following items:

Lease operating expense (LOE) increased due to higher operating costs for all of our operations and significantly higher wind storm insurance costs for our Gulf of Mexico operations. In addition, our LOE was adversely impacted in 2007 by repair expenditures of $36 million ($0.58 per Mcfe) related to 2005 hurricanes Katrina and Rita.

Although our production subject to production taxes increased 18% in the first quarter of 2007 as compared to the same period of 2006, our production tax expense remained unchanged for those periods because of a 16%

decrease in natural gas prices for such production. On an Mcfe basis, production and other taxes decreased because of the 15% increase in our production from the Gulf of Mexico that is not subject to production taxes.

The increase in our depreciation, depletion and amortization (DD&A) rate resulted from higher cost reserve additions. The cost of reserve additions was adversely impacted by escalating costs for drilling goods and services during 2006 and the first quarter of 2007. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.05 per Mcfe for the first quarter of 2007 and $0.07 per Mcfe for the first quarter of 2006.

General and administrative (G&A) expense increased approximately $0.10 per Mcfe primarily due to an increase in a litigation settlement reserve associated with a statewide royalty owner class action lawsuit in Oklahoma. This increase was partially offset by a decrease in stock-based compensation and incentive compensation expense. Stock compensation expense decreased as a result of the reduced probability that a tranche of our performance-based restricted stock issued in 2004 will vest. Our incentive compensation expense is lower as a result of lower adjusted net income (as defined in our incentive compensation plan) for the first quarter of 2007 as compared to the same period of the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. During the first quarter of 2007, we capitalized $9 million of direct internal costs as compared to $10 million in 2006.

In the first quarter of 2006, we recorded a $30 million benefit in Operating expenses Other from our business interruption insurance coverage relating to the disruptions to our Gulf Coast operations caused by the 2005 storms.

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International Operations. Our international operating expenses for the first quarter of 2007, stated on an Mcfe basis, increased 197% over the same period of 2006. The increase was primarily related to the following items:

LOE decreased, on an Mcfe basis, due to the timing of liftings of production in the first quarter of 2007 compared to the same period of 2006. Actual LOE costs increased primarily due to firm pipeline capacity for the first quarter of 2007 that we purchased in anticipation of our first production in the U.K.

Production and other taxes increased as a result of the timing of liftings of production in Malaysia and China. Our initial liftings in China began in the third quarter of 2006.

DD&A, on an Mcfe basis, increased as a result of higher cost reserve additions in Malaysia. DD&A expense was also impacted by the increased liftings of production in China.

G&A expense decreased due to a reduction in our accrual related to our U.K. Bonus Plans. In the first quarter of 2007, the value of the shares of our U.K. subsidiary decreased due to the disappointing results of the recent #7 development well in our Grove Field. Please see Note 11, Stock-Based Compensation *U.K. Bonus Plans* to our consolidated financial statements appearing earlier in this report for a description of these plans.

We recorded a ceiling test writedown of $47 million associated with our U.K. full cost pool in the first quarter of 2007.

Interest Expense. The increase in interest expense for the first quarter of 2007 resulted primarily from the April 13, 2006 issuance of $550 million principal amount of our 6 5/8% Senior Subordinated Notes due 2016, partially offset by the May 3, 2006 redemption of $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012.

Commodity Derivative Income (Expense). The following table presents information about the components of commodity derivative income (expense) for the indicated period.

	Three Months Ended March 31,	
	2007	**2006**
	(In millions)	
Cash flow hedges:		
Hedge ineffectiveness	$	$ 5
Other derivative contracts:		
Unrealized gain (loss) due to changes in fair market value	(246)	2
Realized gain (loss) on settlement	88	(1)
Total commodity derivative income (expense)	$ (158)	$ 6

Hedge ineffectiveness is associated with our hedging contracts that qualify 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 these open contracts during the period.

Taxes. The effective tax rates for the first quarter of 2007 and 2006 were 23% and 36%, respectively. Our reported earnings for the first quarter of 2007 before the UK ceiling test writedown were a net loss of $49 million. During the quarter we recorded a $24 million increase in our valuation allowance related to UK net operating loss carryforwards associated with the writedown that are not currently expected to be realized. As a result, the ceiling test writedown, without an associated tax benefit, increased our reported net loss for the quarter to $96 million resulting in an effective tax rate that was less than the federal statutory tax rate. This was partially offset by state income taxes associated with income from various states in which we have operations and the excess of the Malaysia statutory tax rate over the U.S.

federal statutory rate. 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 accomplish this through successful drilling programs and the acquisition of properties. These activities require substantial capital expenditures. Over the long term, we have successfully grown our reserve base and production, resulting in growth in our net cash flows from operating activities. Fluctuations in commodity prices and the 2005 hurricanes have been the primary reason for short-term changes in our cash flow from operating activities.

In August 2006, we reached an agreement with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita (business interruption, property damage and control of well/operator s extra expense) for $235 million.

We establish a capital budget at the beginning of each calendar year based in part 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, contractual capital commitments beyond 2007 are not significant. Our 2007 capital budget exceeds currently expected cash flow from operations by approximately $400 million. We anticipate that the shortfall will be made up with cash on hand and borrowings under our credit arrangements.

On October 15, 2007, our 7.45% Senior Notes with an aggregate principal amount of $125 million become due. We currently plan to fund the repayment with borrowings under our credit arrangements or by accessing the capital markets.

Credit Arrangements. In December 2005, we entered into a revolving credit facility that matures in December 2010. Our credit facility provides for initial loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments may be increased to a maximum aggregate amount of $1.5 billion if the current 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 the 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, plus a margin that is based on a grid of our debt rating (100 basis points per annum at March 31, 2007). At April 25, 2007, we had outstanding borrowings of $185 million and $51 million of undrawn letters of credit 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, and other noncash charges and expenses including unrealized gains and losses on commodity derivatives 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 net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At March 31, 2007, we were in compliance with all of our debt covenants.

We also have a total of $150 million of borrowing capacity under money market lines of credit with various banks. At April 25, 2007, we had outstanding borrowings of $60 million under our money market lines.

As of April 25, 2007, we had approximately $753 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. Our working capital balances also are affected by fluctuations in the fair value of our outstanding commodity derivative instruments. We had a working capital deficit of $440 million as of March 31, 2007. This compares to a working capital deficit of $272 million as of December 31, 2006. The increase in our working capital deficit at March 31, 2007 is due to a decrease in our cash and short term investments during the quarter to fund a portion of our capital program and the change in the fair value of our commodity derivative instruments. At March 31, 2007, the fair value of our short-term derivatives was a net liability of $41 million. At December 31, 2006, this item was a net short-term derivative asset of $200 million (see Note 7, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements).

Cash Flows from Operations. Cash flows from operations primarily are 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, to help ensure that we have adequate cash flow to fund our capital programs and to manage price risks and returns on some of our acquisitions and drilling programs. 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 or credits.

Our net cash flow from operations was $335 million for the three months ended March 31, 2007 compared to $340 million for the same period in 2006. Even though our revenues and the settlement of our derivative contracts increased during the first quarter of 2007, our operating costs and interest expense increased significantly resulting in a decrease in cash flows for the three months ended March 31, 2007 over the same period of 2006.

Capital Expenditures. Our capital spending for the first quarter of 2007 was $507 million, a 30% increase from first quarter 2006 capital spending of $390 million. The 2007 amount excludes recorded asset retirement cost of $14 million. Of the $507 million, we invested $393 million in domestic exploitation and development, $44 million in domestic exploration (exclusive of exploitation and leasehold activity), $14 million in domestic leasehold activity and $56 million internationally.

We budgeted $1.8 billion for capital spending in 2007, excluding acquisitions. This total includes $50 million for continuing hurricane repairs in the Gulf of Mexico and excludes $100 million for capitalized interest and overhead. Approximately 24% of the $1.8 billion 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, 38% to the Mid-Continent, 8% to the Rocky Mountains and 11% 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 and size of acquisitions are unpredictable. Historically, with the exception of 2006, 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 quarter of 2007 was $131 million. During the first quarter of 2007, we borrowed a net $127 million under our credit arrangements.

In October 2007, our $125 million principal amount of 7.45% Senior Notes will become due. We currently plan to fund the repayment with borrowings under our credit arrangements or by accessing the capital markets.

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Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of March 31, 2007.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
7.45% Senior Notes due 2007	$ 125	$ 125	$	$	$
7 5/8% Senior Notes due 2011	175		175		
6 5/8% Senior Subordinated Notes due 2014	325				325
6 5/8% Senior Subordinated Notes due 2016	550				550
Total debt	1,175	125	175		875
Other obligations:					
Interest payments	570	81	214	116	159
Net derivative liabilities	202	39	163		
Asset retirement obligations	275	36	95	34	110
Operating leases	239	104	117	8	10
Deferred acquisition payments	9	3	4	2	
Oil and gas activities (1)	161				
Total other obligations	1,456	263	593	160	279
Total contractual obligations	$ 2,631	$ 388	$ 768	$ 160	$ 1,154

(1) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, drilling wells, obtaining

and processing seismic data and fulfilling other cash commitments. At March 31, 2007, these work related commitments total $161 million and are comprised of $83 million in the United States and $78 million internationally. These amounts are not included by maturity because their timing cannot be accurately predicted.

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 hedged production is not subject to material basis risk. 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 75-85% of 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 currently averaging about $13-$15 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 sales from our operations in Malaysia typically sells at Tapis, or about even with WTI. Oil sales from our operations in China typically sells at $10-$12 per barrel less than WTI.

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Between March 31, 2007 and April 25, 2007, we entered into additional natural gas price derivative contracts set forth in the table below. None of the contracts below have been designated for hedge accounting.

		NYMEX Contract Price per MMBtu				
			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Volume in MMMBtus**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
October 2007 December 2007						
Price swap contracts	610	$ 9.65				
January 2008 March 2008						
Price swap contracts	910	9.65				
April 2008 June 2008						
Collar contracts	1,820		$ 7.50 - $7.75	$ 7.63	$ 9.00 - $9.05	$ 9.03
July 2008 September 2008						
Collar contracts	1,840		7.50 - 7.75	7.63	9.00 - 9.05	9.03
October 2008 December 2008						
Collar contracts	620		7.50 - 7.75	7.63	9.00 - 9.05	9.03

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@newfield.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, 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 capital resources; and

the other factors affecting our business described under the caption Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2006.

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.

Barrel or Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel 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.

Deep shelf. We consider the deep shelf to be structures located on the Shelf at depths generally greater than 14,000 feet in over pressured horizons where there has been limited or no production from deeper stratigraphic zones.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

Development well. A well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drill are located in the Mid-Continent or the Monument Butte Field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. A well drilled to find and produce oil or natural gas reserves that is not a development well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

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 barrel 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 barrel of crude oil or condensate.

MMS. The Minerals Management Service of the United States Department of the Interior.

NYMEX. The New York Mercantile Exchange.

Probable reserves. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

Proved reserves. In general, the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

Shelf. The U.S. Outer Continental Shelf of the Gulf of Mexico. Water depths generally range from 50 feet to 1,000 feet.

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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 flows 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 and the discussion and tables in Note 7, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing earlier in this report.

Interest Rates

At March 31, 2007, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$ 95
Money market line of credit		32
7.45% Senior Notes due 2007[(1) (2)]	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	$ 227

(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.

(2) Classified as current debt on our consolidated balance sheet at March 31, 2007.

We consider our interest rate exposure to be minimal because, as of March 31, 2007, about 83% of our 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 March 31, 2007.

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 March 31, 2007 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 first quarter of 2007 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

In December 2002, a lawsuit against our Mid-Continent subsidiary was filed in Beaver County, Oklahoma and was later certified as a class action royalty owner lawsuit. The complaint alleges that we improperly reduced royalty payments for certain expenses and charges, and also claims breach of contract and breach of fiduciary duties, among other claims. In April 2007, we entered into a non-binding settlement agreement, subject to final documentation and court approval, with respect to the lawsuit. In the first quarter of 2007, we increased our litigation settlement reserve for the lawsuit, which resulted in a charge to earnings that was recorded under the caption General and administrative on our consolidated income statement.

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

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 three months ended March 31, 2007.

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(2)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 January 31, 2007				
February 1 February 28, 2007	7,268	$ 48.08		
March 1 March 31, 2007				

(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.

(2) On November 20, 2006, we announced a program pursuant to which stockholders owning fewer than 100 shares of our common stock could sell their shares at no cost to them. We did not purchase any shares under the program but we did pay for the costs to administer the program. The program expired on January 26, 2007.

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Item 6. Exhibits

(a) Exhibits:

* Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.

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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: April 27, 2007

By: /s/ TERRY W. RATHERT
Terry W. Rathert
Senior Vice President and Chief Financial Officer

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EXHIBIT INDEX

Exhibit Number	Description
* 10.8	Newfield Exploration Company Deferred Compensation Plan as Amended and Restated
* 10.9	Amended and Restated Newfield Exploration Company Change of Control Severance Plan
* 10.10.1	Form of Amended and Restated Change of Control Severance Agreement between Newfield and each of David A. Trice, David F. Schaible and Terry W. Rathert dated effective as of March 9, 2007
* 10.10.2	Form of Change of Control Severance Agreement between Newfield and Michael Van Horn dated effective as of March 9, 2007
* 10.10.3	Form of Amended and Restated Change of Control Severance Agreement between Newfield and each of Lee K. Boothby, George T. Dunn, Gary D. Packer and William D. Schneider dated effective as of March 9, 2007
*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

* Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.