NEWFIELD EXPLORATION CO /DE/
Form 10-Q
October 29, 2007

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

(Mark One)

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

For the Quarterly Period Ended September 30, 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 October 25, 2007, there were 130,905,118 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)

	September 30, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 141	$ 80
Short-term investments	43	10
Accounts receivable	329	374
Inventories	74	44
Derivative assets	93	280
Deferred taxes	10	¾
Other current assets	36	58
Assets of discontinued operations	11	5
Total current assets	737	851
Oil and gas properties (full cost method, of which $1,190 at September 30, 2007 and $970 at December 31, 2006 were excluded from amortization)	9,349	8,689
Less accumulated depreciation, depletion and amortization	(3,802)	(3,234)
	5,547	5,455
Furniture, fixtures and equipment, net	33	28
Derivative assets	26	19
Other assets	24	20
Goodwill	62	62
Assets of discontinued operations	177	200
Total assets	$ 6,606	$ 6,635
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 49	$ 58
Current debt	124	124
Accrued liabilities	598	641
Advances from joint owners	37	90
Asset retirement obligation	4	40
Derivative liabilities	103	80
Deferred taxes	¾	63
Liabilities of discontinued operations	14	27
Total current liabilities	929	1,123

Other liabilities		32		28
Derivative liabilities		181		179
Long-term debt		1,049		1,048
Asset retirement obligation		51		225
Deferred taxes		1,098		963
Liabilities of discontinued operations		11		7
Total long-term liabilities		2,422		2,450
Commitments and contingencies (Note 6)		¾		¾
Stockholders equity:				
Preferred stock ($0.01 par value; 5,000,000 shares authorized; no shares issued)		¾		¾
Common stock ($0.01 par value; 200,000,000 shares authorized at September 30, 2007 and December 31, 2006; 132,497,291 and 131,063,555 shares issued and outstanding at September 30, 2007 and December 31, 2006, respectively)		1		1
Additional paid-in capital		1,249		1,198
Treasury stock (at cost; 1,891,535 and 1,879,874 shares at September 30, 2007 and December 31, 2006, respectively)		(31)		(30)
Accumulated other comprehensive income (loss):				
Foreign currency translation adjustment		15		14
Commodity derivatives		¾		(5)
Minimum pension liability		(3)		(3)
Retained earnings		2,024		1,887
Total stockholders equity		3,255		3,062
Total liabilities and stockholders equity	$	6,606	$	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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Oil and gas revenues	$ 419	$ 425	$ 1,384	$ 1,246
Operating expenses:				
Lease operating	64	36	268	155
Production and other taxes	25	12	63	43
Depreciation, depletion and amortization	162	159	539	434
General and administrative	37	33	107	89
Ceiling test writedown	¾	6	¾	6
Other	¾	(6)	¾	(11)
Total operating expenses	288	240	977	716
Income from operations	131	185	407	530
Other income (expense):				
Interest expense	(29)	(22)	(80)	(64)
Capitalized interest	13	11	35	33
Commodity derivative income (expense)	38	247	(43)	299
Other	1	2	3	7
	23	238	(85)	275
Income from continuing operations before income taxes	154	423	322	805
Income tax provision:				
Current	57	18	78	30
Deferred	5	138	47	264
	62	156	125	294
Income from continuing operations	92	267	197	511
Loss from discontinued operations, net of tax	(9)	(1)	(60)	(2)
Net income	$ 83	$ 266	$ 137	$ 509

Earnings per share:				
Basic ¾				
Income from continuing operations	$ 0.72	$ 2.11	$ 1.54	$ 4.03
Loss from discontinued operations	(0.07)	(0.01)	(0.47)	(0.01)
Net income	$ 0.65	$ 2.10	$ 1.07	$ 4.02
Diluted ¾				
Income from continuing operations	$ 0.70	$ 2.07	$ 1.51	$ 3.96
Loss from discontinued operations	(0.06)	(0.01)	(0.46)	(0.01)
Net income	$ 0.64	$ 2.06	$ 1.05	$ 3.95
Weighted average number of shares outstanding for basic earnings per share	128	126	127	127
Weighted average number of shares outstanding for diluted earnings per share	131	129	130	129

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)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Cash flows from operating activities:		
Net income	$ 137	$ 509
Adjustments to reconcile net income to net cash provided by continuing operating activities:		
Loss from discontinued operations, net of tax	60	2
Depreciation, depletion and amortization	539	434
Deferred taxes	47	264
Stock-based compensation	18	18
Early redemption premium	¾	8
Commodity derivative (income) expense		
Total (gains) losses	43	(299)
Realized gains	174	73
Ceiling test writedown	¾	6
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(12)	82
Increase in inventories	(29)	(18)
(Increase) decrease in other current assets	18	(22)
Increase in other assets	7	12
Increase (decrease) in accounts payable and accrued liabilities	(8)	42
Decrease in commodity derivative liabilities	(2)	(13)
Increase (decrease) in advances from joint owners	(53)	40
Increase in other liabilities	4	5
Net cash provided by continuing activities	943	1,143
Net cash provided by (used in) discontinued activities	(12)	2
Net cash provided by operating activities	931	1,145
Cash flows from investing activities:		
Acquisition of oil and gas properties	(578)	¾
Additions to oil and gas properties	(1,532)	(1,126)
Insurance recoveries	¾	45
Proceeds from sale of oil and gas properties	1,281	¾
Additions to furniture, fixtures and equipment	(7)	(4)
Purchases of short-term investments	(43)	(541)
Redemption of short-term investments	24	511
Net cash used in continuing activities	(855)	(1,115)

Net cash used in discontinued activities	(41)	(118)
Net cash used in investing activities	(896)	(1,233)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	2,909	491
Repayments of borrowings under credit arrangements	(2,909)	(491)
Proceeds from issuance of senior subordinated notes	¾	550
Repayment of senior subordinated notes	¾	(250)
Payments to discontinued operations	(38)	(121)
Proceeds from issuances of common stock	18	9
Stock-based compensation excess tax benefit	8	3
Purchases of treasury stock	(1)	(3)
Net cash provided by (used in) continuing activities	(13)	188
Net cash provided by discontinued activities	38	121
Net cash provided by financing activities	25	309
Effect of exchange rate changes on cash and cash equivalents	1	5
Increase in cash and cash equivalents	61	226
Cash and cash equivalents from continuing operations, beginning of period	52	38
Cash and cash equivalents from discontinued operations, beginning of period	28	1
Cash and cash equivalents, end of period	$ 141	$ 265

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	1.4				18			18
Stock-based compensation					25			25
Treasury stock, at cost				(1)				(1)
Stock-based compensation excess tax benefit					8			8
Comprehensive income:								
Net income						137		137
Foreign currency translation adjustment, net of tax of ($1)							1	1
Reclassification adjustments for settled hedging positions, net of tax of $2							(3)	(3)
Reclassification adjustments for discontinued cash flow hedges, net of tax of ($1)							2	2
Changes in fair value of outstanding hedging positions, net of tax of ($4)							6	6
Total comprehensive income								143
Balance, September 30,	132.5	$ 1	(1.9)	$ (31)	$ 1,249	$ 2,024	$ 12	$ 3,255

2007

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

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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 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 deepwater Gulf of Mexico. Internationally, we are active offshore Malaysia and China.

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.

On September 17, 2007, we entered into an agreement to sell all of our interests in the U.K. North Sea for $486 million. As a result of this agreement, the results of operations and financial position of our U.K. subsidiaries are reflected in our financial statements as discontinued operations. This reclassification affects not only the 2007 presentation of our financial statements, but also the presentation of all prior period financial statements. See Note 2, Discontinued Operations. Except where noted, discussions in these notes relate to our continuing operations only.

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 associated with 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.

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 yet 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 September 30, 2007 consisted of approximately 333,000 barrels of crude oil valued at cost of $12 million. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 nine months ended September 30, 2007 are set forth below (in millions):

Balance as of January 1, 2007	$ 264
Accretion expense	8
Additions	5
Revisions	11
Settlements [1]	(233)
Balance of ARO as of September 30, 2007	$ 55

(1) $216 million relates to our Gulf of Mexico and Cherokee Basin asset sales.

Stock-Based Compensation

On January 1, 2006, we adopted Financial Accounting Standards Board (FASB) Statement (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) eliminated the use of Accounting Principles Board (APB) Opinion No. 25 (APB 25), Accounting for Stock Issued to Employees, 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 12, Stock-Based Compensation, for a full discussion of our stock-based compensation.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109. 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 has a greater than 50% likelihood 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.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We adopted the provisions of FIN 48 on January 1, 2007. The adoption did not result in a material adjustment to our tax liability for unrecognized income tax benefits. At September 30, 2007, we determined that our uncertain tax positions were immaterial.

If applicable, we would recognize interest and penalties related to uncertain tax positions in interest expense. As of September 30, 2007, we had not accrued interest related to uncertain tax positions because we have currently overpaid our 2007 estimated tax liability.

The tax years 2004-2006 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

2. Discontinued Operations:

On September 17, 2007, we entered into an agreement to sell all of our interests in the U.K. North Sea for $486 million. We will recognize a gain in the fourth quarter as a result of the completion of the sale in early October 2007. The historical results of operations of our U.K. North Sea subsidiaries are reflected in our financial statements as discontinued operations. This reclassification affects not only the 2007 presentation of our financial statements, but also the presentation of all prior period financial statements.

The summarized financial results and financial position of the discontinued operations for the periods presented below are as follows:

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)			
Revenues	$ 5	$ ¾	$ 8	$ ¾
Operating expenses [(1)]	8	1	61	3
Loss from operations	(3)	(1)	(53)	(3)
Commodity derivative expense	(3)	¾	(3)	¾
Other expense [(2)]	(3)	(1)	(4)	(1)
Loss before income taxes	(9)	(2)	(60)	(4)
Income tax benefit	¾	(1)	¾	(2)
Loss from discontinued operations	$ (9)	$ (1)	$ (60)	$ (2)

(1) Operating expenses for the nine months ended September 30, 2007 include the ceiling test writedown of $47 million recorded in the first quarter of 2007.

(2) Other expense primarily consists of U.K. withholding tax expense with respect to interest on intercompany loans.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	September 30, 2007	December 31, 2006
	(In millions)	
Accounts receivable	$ 4	$ 4
Inventories	3	¾
Derivative assets	1	¾
Other current assets	3	1
Total current assets	11	5
Oil and gas properties, net of accumulated depreciation depletion and amortization	175	200
Furniture, fixtures and equipment, net	1	¾
Other assets	1	¾
Total other assets	177	200
Total assets	$ 188	$ 205
Accounts payable	$ 3	$ 1
Derivative liabilities	4	¾
Accrued liabilities	7	26
Total current liabilities	14	27
Deferred taxes	¾	¾
Asset retirement obligation	11	7
Total long-term liabilities	11	7
Total liabilities	$ 25	$ 34

In May 2007, we entered into several natural gas swaps related to our U.K. production. These trades are for October 2007 through September 2008 with a weighted average price of $7.55 per MMBtu. We also entered into one natural gas collar with a put price of $6.98 and a call price of $10.19 per MMBtu. The estimated fair value of these contracts at September 30, 2007 was approximately a $3 million liability.

As of September 30, 2007, we had U.K. NOL carryforwards for income tax purposes of approximately $100 million that could be used in future years to offset taxable income. Because of the sale of our U.K. assets, we will not be able to utilize these NOLs, and therefore, a valuation allowance was established for them.

3. Earnings Per Share:

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

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions, except per share data)			
Income (numerator):				
Income from continuing operations	$ 92	$ 267	$ 197	$ 511
Loss from discontinued operations, net of tax	(9)	(1)	(60)	(2)
Net income basic and diluted	$ 83	$ 266	$ 137	$ 509
Weighted average shares (denominator):				
Weighted average shares basic	128	126	127	127
Dilution effect of stock options and unvested restricted stock outstanding at end of period	3	3	3	2
Weighted average shares diluted	131	129	130	129
Earnings per share:				
Basic ¾				
Income from continuing operations	$ 0.72	$ 2.11	$ 1.54	$ 4.03
Loss from discontinued operations	(0.07)	(0.01)	(0.47)	(0.01)
Basic earnings per share	$ 0.65	$ 2.10	$ 1.07	$ 4.02
Diluted ¾				
Income from continuing operations	$ 0.70	$ 2.07	$ 1.51	$ 3.96
Loss from discontinued operations	(0.06)	(0.01)	(0.46)	(0.01)
Diluted earnings per share	$ 0.64	$ 2.06	$ 1.05	$ 3.95

There were no antidilutive shares for the three and nine months ended September 30, 2007 and 2006.

4. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

	September 30, 2007	December 31, 2006
	(In millions)	
Subject to amortization	$ 8,159	$ 7,719

Not subject to amortization:		
Exploration wells in progress	305	182
Development wells in progress	29	49
Capitalized interest	99	94
Fee mineral interests	23	23
Other capital costs:		
Incurred in 2007	245	
Incurred in 2006	84	88
Incurred in 2005	53	89
Incurred in 2004 and prior	352	445
Total not subject to amortization	1,190	970
Gross oil and gas properties	9,349	8,689
Accumulated depreciation, depletion and amortization	(3,802)	(3,234)
Net oil and gas properties	$ 5,547	$ 5,455

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil and gas properties not subject to amortization represent investments in unproved properties and major development projects in which we own an interest. These unproved property costs include unevaluated leasehold acreage, geological and geophysical data costs associated with leasehold or drilling interests, costs associated with wells currently drilling and capitalized interest. We exclude these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. Unproved property costs are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant. Costs associated with exploration and development wells in progress are transferred to the amortization base upon the determination of whether proved reserves can be assigned to the properties, which is generally based on drilling results. All other costs excluded from the amortization base are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the amortization base or a charge is made against earnings for those international operations with respect to which a reserve base has not yet been established. We believe that our evaluation activities related to substantially all of the properties associated with costs not currently subject to amortization will be completed within four to ten years.

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.

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. The writedown is presented in Loss from discontinued operations, net of tax on our consolidated statement of income.

Acquisition of Rocky Mountain Assets

In June 2007, we closed the $578 million acquisition of Stone Energy Corporation s Rocky Mountain assets. These assets increase our existing presence and provide an entry into large developments in many of the Rocky Mountains most attractive areas. Our consolidated financial statements include the cash flows and results of operations for these assets subsequent to June 30, 2007. This acquisition was financed through borrowings under our revolving credit agreement.

Gulf of Mexico Asset Sale

On August 6, 2007, we closed the sale of substantially all of our properties in the Gulf of Mexico to McMoRan Exploration Co. for $1.1 billion in cash and the assumption of liabilities associated with the future abandonment of wells and platforms. We retained most of our deepwater properties and interests in some exploration prospects on the shelf. The cash flows and results of operations for the assets included in the sale are included in our consolidated financial statements up to the closing date.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cherokee Basin Asset Sale

On September 21, 2007, we closed the sale of our coal bed methane assets in the Cherokee Basin of northeastern Oklahoma for $128 million in cash. The cash flows and results of operations for these assets are included in our consolidated financial statements up to the closing date.

Pro Forma Results

The unaudited pro forma results presented below for the three months ended September 30, 2006 and nine months ended September 30, 2007 and 2006 have been prepared to give effect to the Rocky Mountain asset acquisition described above on our results of operations as if it had been consummated on January 1, 2006. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(Unaudited) (In millions, except per share data)		
Pro forma:			
Revenue	$ 450	$1,432	$1,318
Income from operations	195	468	557
Net income	275	198	535
Basic earnings per share	$2.18	$ 1.55	$ 4.23
Diluted earnings per share	$2.14	$ 1.52	$ 4.15

5. Debt:

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

	September 30, 2007	December 31, 2006
	(In millions)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$ ¾	$ ¾
LIBOR based loans	¾	¾
Total bank revolving credit facility	¾	¾
Money market line of credit (1)	¾	¾
Total credit arrangements	¾	¾
$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)	(1)	(2)

Total senior unsecured notes	298	297
Total senior unsecured debt	298	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	1,173	1,172
Less: Current portion of debt (2)	124	124
Total long-term debt	$ 1,049	$ 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, amounts outstanding under these obligations, if any, are 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.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Credit Arrangements

In June 2007, we entered into a new revolving credit facility that matures in June 2012. This facility replaces our previous facility. The terms of the credit facility provide for initial loan commitments of $1.25 billion from a syndicate of banks, led by JPMorgan Chase as the agent bank. The loan commitments under the credit facility may be increased to a maximum aggregate amount of $1.65 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 (87.5 basis points per annum at September 30, 2007). At September 30, 2007, we had no borrowings outstanding under the credit facility.

Under our new credit facility and our previous credit facility, we pay commitment fees on the undrawn amounts based on a grid of our debt rating (0.175% per annum at September 30, 2007). We incurred fees under these arrangements of approximately $0.5 million and $1.8 million for the three and nine months ended September 30, 2007, respectively, which are recorded in interest expense on our consolidated statement of income.

The new 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 and non-cash items (such as depreciation, depletion and amortization expense and unrealized gains and losses on commodity derivatives) of at least 3.5 to 1.0; and, so long as our debt rating is below investment grade, the maintenance of a 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 September 30, 2007, we were in compliance with all of our debt covenants.

As of September 30, 2007, we had $46 million of undrawn letters of credit outstanding under our credit facility. Letters of credit issued under our credit facility are subject to an issuance fee of 12.5 basis points and annual fees based on a grid of our debt rating (87.5 basis points at September 30, 2007).

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $135 million of borrowing capacity under money market lines of credit with various banks. At September 30, 2007, we had no borrowings outstanding under our money market lines.

6. 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 alleged that we improperly reduced royalty payments for certain expenses and charges, and also claimed breach of contract and breach of fiduciary duties, among other claims. In April 2007, we entered into a settlement agreement that has recently received court approval. 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.

7. 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 current operating segments are the United States, Malaysia, China and Other International. The accounting policies of each of our operating segments are the same as those described in Note 1, Organization and Summary of Significant Accounting Policies.

The following tables provide the geographic operating segment information required by SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information,* as well as results of operations of oil and gas producing activities required by SFAS No. 69, *Disclosures about Oil and Gas Producing Activities,* as of and for the three and nine months ended September 30, 2007 and 2006 for continuing operations. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Malaysia	China	Other International	Total
			(In millions)		
Three Months Ended September 30, 2007:					
Oil and gas revenues	$ 384	$ 31	$ 4	$ ¾	$ 419
Operating expenses:					
Lease operating	54	9	1	¾	64
Production and other taxes	20	5	¾	¾	25
Depreciation, depletion and amortization	153	8	1	¾	162
General and administrative	35	1	1	¾	37
Allocated income taxes	44	3	¾	¾	
Net income from oil and gas properties	$ 78	$ 5	$ 1	$ ¾	
Total operating expenses					288
Income from continuing operations					131
Interest expense, net of interest income, capitalized interest and other					(15)
Commodity derivative income					38
Income from continuing operations before income taxes					$ 154
Total long-lived assets	$ 5,159	$ 313	$ 74	$ 1	$ 5,547
Additions to long-lived assets	$ 398	$ 74	$ 5	$ ¾	$ 477

	United States	Malaysia	China	Other International	Total
			(In millions)		
Three Months Ended September 30, 2006:					
Oil and gas revenues	$ 410	$ 13	$ 2	$ ¾	$ 425
Operating expenses:					
Lease operating	33	3	¾	¾	36

Production and other taxes	10	2	¾	¾	12
Depreciation, depletion and amortization	156	2	1	¾	159
Ceiling test writedown	¾	¾	¾	6	6
General and administrative	31	2	¾	¾	33
Other	(6)	¾	¾	¾	(6)
Allocated income taxes	67	2	¾	¾	
Net income (loss) from oil and gas properties	$ 119	$ 2	$ 1	$ (6)	
Total operating expenses					240
Income from continuing operations					185
Interest expense, net of interest income, capitalized interest and other					(9)
Commodity derivative income					247
Income from continuing operations, before income taxes					$ 423
Total long-lived assets	$ 4,892	$ 134	$ 64	$ 1	$ 5,091
Additions to long-lived assets	$ 405	$ 19	$ 7	$ ¾	$ 431

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Malaysia	China (In millions)	Other International	Total
Nine Months Ended September 30, 2007:					
Oil and gas revenues	$ 1,296	$ 60	$ 28	$ ¾	$ 1,384
Operating expenses:					
Lease operating	245	21	2	¾	268
Production and other taxes	51	10	2	¾	63
Depreciation, depletion and amortization	517	15	7	¾	539
General and administrative	104	1	2	¾	107
Allocated income taxes	136	5	5	¾	
Net income from oil and gas properties	$ 243	$ 8	$ 10	$ ¾	
Total operating expenses					977
Income from continuing operations					407
Interest expense, net of interest income, capitalized interest and other					(42)
Commodity derivative expense					(43)
Income from continuing operations before income taxes					$ 322
Total long-lived assets	$ 5,159	$ 313	$ 74	$ 1	$ 5,547
Additions to long-lived assets	$ 1,905	$ 149	$ 17	$ ¾	$ 2,071

	United States	Malaysia	China (In millions)	Other International	Total
Nine Months Ended September 30, 2006:					
Oil and gas revenues	$ 1,208	$ 36	$ 2	$ ¾	$ 1,246
Operating expenses:					
Lease operating	146	9	¾	¾	155

Production and other taxes	35	8	¾	¾	43
Depreciation, depletion and amortization	427	6	1	¾	434
Ceiling test writedown	¾	¾	¾	6	6
General and administrative	86	2	1	¾	89
Other	(11)	¾	¾	¾	(11)
Allocated income taxes	189	4	¾	¾	
Net income (loss) from oil and gas properties	$ 336	$ 7	$ ¾	$ (6)	
Total operating expenses					716
Income from continuing operations					530
Interest expense, net of interest income, capitalized interest and other					(24)
Commodity derivative income					299
Income from continuing operations, before income taxes					$ 805
Total long-lived assets	$ 4,892	$ 134	$ 64	$ 1	$ 5,091
Additions to long-lived assets	$ 1,131	$ 54	$ 20	$ 1	$ 1,206

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. 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. Beginning in the fourth quarter of 2005, we elected not to designate any additional swap, collar and floor contracts that were entered into subsequent to September 30, 2005 as accounting hedges under SFAS No. 133. As a result of the sale of our Gulf of Mexico properties in August 2007, our only remaining cash flow hedges no longer qualified for hedge accounting, resulting in $2 million, net of tax, being reclassified from Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet to Commodity derivative income (expense) on our consolidated income statement.

Derivative Contracts

All of our derivative contracts are now 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.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At September 30, 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 (Liability)
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	(In millions)
October 2007 December 2007							
Price swap contracts	12,340	$ 8.99					$ 28
Collar contracts	19,695		$ 6.50 $8.00	$ 7.13	$ 8.23 $12.40	$ 10.51	17
January 2008 March 2008							
Price swap contracts	6,370	9.11					6
Collar contracts	22,595		8.00	8.00	10.00 12.40	11.04	13
April 2008 June 2008							
Price swap contracts	21,685	7.95					6
Collar contracts	5,715		7.00 8.00	7.64	9.00 9.70	9.34	3
July 2008 September 2008							
Price swap contracts	22,540	7.96					3
Collar contracts	5,760		7.00 8.00	7.64	9.00 9.70	9.34	2
October 2008 December 2008							
Price swap contracts	7,595	7.96					1
Collar contracts	9,255		7.00 8.00	7.93	9.00 10.25	9.89	
January 2009 March 2009							
Collar contracts	11,250		8.00	8.00	9.67 10.25	10.04	(3)
							$ 76

Oil

		NYMEX Contract Price per Bbl							Estimated Fair Value Asset (Liability)
					Collars				
		Swaps	Additional Put		Floors		Ceilings		
Period and Type of Contract	Volume in MBbls	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	(In millions)
October 2007 December 2007									
Price swap contracts	122	$ 63.40	¾	¾	¾	¾	¾	¾	$ (2)
Collar contracts	152		¾	¾	$ 50.00 $60.00	$ 55.46	$ 77.10 $83.25	$ 80.40	(3)
3-Way collar contracts	888		$ 25.00 $50.00	$ 30.00	32.00 60.00	37.10	44.70 82.00	55.31	(20)
January 2008 March 2008									

3-Way collar contracts	819	25.00	29.00	26.56	32.00	35.00	33.00	49.50	52.90	50.29	(22)
April 2008 June 2008											
3-Way collar contracts	819	25.00	29.00	26.56	32.00	35.00	33.00	49.50	52.90	50.29	(21)
July 2008 September 2008											
3-Way collar contracts	828	25.00	29.00	26.56	32.00	35.00	33.00	49.50	52.90	50.29	(20)
October 2008 December 2008											
3-Way collar contracts	828	25.00	29.00	26.56	32.00	35.00	33.00	49.50	52.90	50.29	(19)
January 2009 December 2009											
3-Way collar contracts	3,285	25.00	30.00	27.00	32.00	36.00	33.33	50.00	54.55	50.62	(70)
January 2010 December 2010											
3-Way collar contracts	3,645	25.00	32.00	28.60	32.00	38.00	34.90	50.00	53.50	51.52	(68)
											$ (245)

Basis Contracts

During the third quarter 2007, we added several natural gas basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points, as set forth in the table below.

	Onshore Gulf Coast		Rocky Mountains		Estimated Fair Value Asset
	Volume in MMMBtus	Weighted Average Differential	Volume in MMMBtus	Weighted Average Differential	(Liability) (In millions)
October 2007 December 2007	11,040	$ (0.34)	920	$ (2.68)	$ 2
January 2008 December 2008			4,800	(1.62)	
January 2009 December 2009			5,520	(1.05)	1
January 2010 December 2010			5,520	(0.99)	1
January 2011 December 2011			5,280	(0.95)	1
January 2012 December 2012			4,920	(0.91)	1
					$ 6

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commodity Derivative Income (Expense)

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

	Three Month Period Ended September 30,		Nine Month Period Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Cash flow hedges:				
Hedge ineffectiveness	$	$ (1)	$	$ 5
Other derivative contracts:				
Unrealized loss on discontinued cash flow hedges	(3)		(3)	
Unrealized gain (loss) due to change in fair market value	(20)	210	(211)	221
Realized gain on settlement	61	38	171	73
Total commodity derivative income (expense)	$ 38	$ 247	$ (43)	$ 299

9. Accounts Receivable:

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

	September 30, 2007	December 31, 2006
	(In millions)	
Revenue	$ 133	$ 204
Joint interest	165	141
Property disposition post close receivable	21	¾
Receivable from broker	¾	14
MMS deposits	3	8
Texas severance tax	5	6
Other	2	1
Total accounts receivable	$ 329	$ 374

10. Accrued Liabilities:

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

	September 30, 2007	December 31, 2006
	(In millions)	
Revenue payable	$ 88	$ 95
Accrued capital costs	268	328
Accrued lease operating expenses	50	58
Employee incentive expense	54	63

Accrued interest on notes	24	21
Taxes payable	68	21
Deferred acquisition payments	9	9
Insurance premium payable	9	16
Other	28	30
Total accrued liabilities	$ 598	$ 641

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Comprehensive Income:

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Net income	$ 83	$ 266	$ 137	$ 509
Foreign currency translation adjustment, net of tax of ($1) and $1 for the third quarter of 2007 and 2006, respectively, and ($1) and ($5) for the nine months ended September 30, 2007 and 2006, respectively	(2)	2	1	9
Reclassification adjustments for settled hedging positions, net of tax of $0 and $3 for the third quarter of 2007 and 2006, respectively, and $2 and $15 for the nine months ended September 30, 2007 and 2006, respectively	¾	(6)	(3)	(28)
Reclassification adjustments for discontinued cash flow hedges, net of tax of ($1) and ($0) for the third quarter of 2007 and 2006, respectively, and ($1) and ($0) for the nine months ended September 30, 2007 and 2006, respectively	2	¾	2	¾
Changes in fair value of outstanding hedging positions, net of tax of ($0) and ($15) for the third quarter of 2007 and 2006, respectively, and ($4) and ($28) for the nine months ended September 30, 2007 and 2006, respectively	¾	28	6	52
Total comprehensive income	$ 83	$ 290	$ 143	$ 542

12. Stock-Based Compensation:

Historically, we have used, and we anticipate continuing to use, unissued shares of stock when stock options are exercised. At September 30, 2007, we had approximately 2.7 million additional shares available for issuance pursuant to our existing employee and director plans. Of these shares, 1.6 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. Of the 1.6 million shares that can be granted as restricted shares, 0.4 million of such shares can be issued under our 2004 Omnibus Stock Plan.

We recorded stock-based compensation expense of $10 million and $25 million (pre-tax) for all plans for the three and nine months ended September 30, 2007, respectively. Of these amounts, $3 million and $7 million were capitalized in oil and gas properties for the three and nine months ended September 30, 2007, respectively. For the nine months ended September 30, 2007, we reported $8 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows. For the three and nine months ended September 30, 2006, we recorded stock-based compensation expense of $6 million (pre-tax) and $18 million (pre-tax), respectively. Of these amounts, $2 million and $5 million were capitalized in oil and gas properties for the three and nine months ended September 30, 2006, respectively.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of September 30, 2007, we had approximately $72 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 about stock option activity for the nine months ended September 30, 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 (In millions)[(1)]
Outstanding at December 31, 2006	5.6	$ 23.68	$ 10.71	6.3	$ 124
Granted	¾	¾	¾	¾	¾
Exercised	(0.8)	21.99	9.89	¾	19
Forfeited	(0.3)	29.50	13.39	¾	6
Outstanding at September 30, 2007	4.5	$ 23.55	$ 10.65	5.5	$ 110
Exercisable at September 30, 2007	2.9	$ 20.76	$ 9.34	4.8	$ 79

(1) The intrinsic value of a stock option is the amount by which the 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 following table summarizes information about stock options outstanding and exercisable at September 30, 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	40	0.9	$ 7.97	40	$ 7.97
10.01 to 12.50	10	1.1	10.78	10	10.78
12.51 to 15.00	413	2.3	14.72	413	14.72
15.01 to 17.50	981	4.6	16.63	875	16.63
17.51 to 22.50	715	4.4	18.97	589	18.95
22.51 to 27.50	749	6.2	24.75	393	24.72
27.51 to 35.00	1,336	7.1	31.10	489	30.90
35.01 to 41.72	239	7.6	38.13	73	38.46
	4,483	5.5	$ 23.55	2,882	$ 20.76

On September 30, 2007, the last reported sales price of our common stock on the New York Stock Exchange was $48.16 per share.

Restricted Shares. At September 30, 2007, our employees held 1.1 million restricted shares or restricted share units that primarily vest over the service period of four to five years. The vesting of these shares and units is dependant upon the applicable employee s continued service with our company.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition, at September 30, 2007, our employees held 1.7 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 is being 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 or 2010. The percentage of 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 as of June 30, 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 $100,000 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 other than at an annual meeting receive a number of restricted shares determined by dividing $100,000 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 September 30, 2007, 85,592 shares remained available for grants under this plan.

The following table provides information about restricted share activity for the nine months ended September 30, 2007:

	Service-Based	Performance/ Market-Based	Total
	(In thousands, except per share data)		
Non-vested shares outstanding at December 31, 2006	667	1,516	2,183
Granted	619	293	912
Forfeited	(95)	(79)	(174)
Vested	(60)	¾	(60)
Non-vested shares outstanding at September 30, 2007	1,131	1,730	2,861
Weighted average grant date fair value per share of shares granted during the period	$ 44.23	$ 24.04	$ 36.82
Total fair value of shares vested during the period	$ 1,799	$ ¾	$ 1,799

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 third quarter of 2007, options to purchase 30,700 shares of our common stock at a weighted average fair value of $11.48 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 4.93%, an expected life of 6 months and weighted-average volatility of 32.61%. At September 30, 2007, 629,257 shares of our common stock remained available for issuance under this plan.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. 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 September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)			
Amount computed using the statutory rate	$ 54	$ 148	$ 113	$ 282
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect	3	2	6	6
Net effect of different tax rates in non-U.S. jurisdictions	4	2	7	2
Tax credits and other	1	4	(1)	4
Total provision for income taxes	$ 62	$ 156	$ 125	$ 294

As of September 30, 2007, we had NOL carryforwards for international income tax purposes of approximately $17 million that may be used in future years to offset taxable income. As of September 30, 2007, we 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.

14. Subsequent Events:

On October 5, 2007, we closed the sale of all of our interests in the U.K. North Sea. We received $511 million in proceeds, which was the agreed upon sales price plus working capital at the time of closing. We will record a gain on the sale in the fourth quarter of 2007. We expect the gain to be approximately $325 million to $350 million.

On October 15, 2007, our $125 million principal amount of 7.45% Senior Notes became due. We repaid the notes with cash on hand.

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 deepwater Gulf of Mexico. Internationally, we have operations offshore Malaysia and China.

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.

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production. We use hedging to reduce our exposure to fluctuations in natural gas and oil prices. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive 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 continue to develop existing reserves or locate 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 8, 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 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

We completed several significant transactions during the last several months that had a meaningful impact on our 2007 results of operations and cash flows.

In late June 2007, we completed the $578 million acquisition of Stone Energy Corporation s Rocky Mountain assets.

In August 2007, we completed the sale of substantially all of our properties in the Gulf of Mexico for $1.1 billion in cash and the assumption of liabilities associated with future abandonment of wells and platforms.

In September 2007, we completed the sale of our coal bed methane assets in the Cherokee Basin of northeastern Oklahoma for $128 million in cash.

In October 2007, we completed the sale of all of our interests in the U.K. North Sea for $486 million pursuant to an agreement entered into in September 2007. The historical results of operations of our U.K. North Sea subsidiaries are reflected in our financial statements as discontinued operations. This reclassification affects not only the 2007 presentation of our financial statements, but also the presentation of all prior period financial statements. Except where noted, discussions in this report relate to continuing operations.

See Note 4, Oil and Gas Assets, to our consolidated financials statements set forth in Item 1 of this report for discussion regarding the acquisition and sales transactions.

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 third quarter of 2007 were slightly lower than the comparable period of 2006 due to lower natural gas production and natural gas prices, partially offset by higher oil and condensate production and oil and condensate prices. Revenues for the first nine months of 2007 were 11% higher than the same period of the prior year due to higher natural gas and oil and condensate production and oil and condensate prices, partially offset by slightly lower natural gas prices.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Percentage Increase (Decrease)	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Percentage Increase (Decrease)
Production (1):						
United States:						
Natural gas (Bcf)	46.9	51.2	(8%)	154.9	143.6	8%
Oil and condensate (MBbls)	1,669	1,674		5,285	4,609	15%
Total (Bcfe)	56.9	61.2	(7%)	186.6	171.2	9%
International:						
Natural gas (Bcf)						
Oil and condensate (MBbls)	488	225	117%	1,401	593	136%
Total (Bcfe)	2.9	1.4	117%	8.4	3.6	136%
Total:						
Natural gas (Bcf)	46.9	51.2	(8%)	154.9	143.6	8%
Oil and condensate (MBbls)	2,157	1,899	14%	6,686	5,202	29%
Total (Bcfe)	59.8	62.6	(4%)	195.0	174.8	12%

Average Realized Prices (2)**:**						
United States:						
Natural gas (per Mcf)	$ 5.81	$ 6.21	(6%)	$ 6.38	$ 6.68	(4%)
Oil and condensate (per Bbl)	65.71	54.21	21%	57.03	53.22	7%
Natural gas equivalent (per Mcfe)	6.71	6.67	1%	6.91	7.03	(2%)
International:						
Natural gas (per Mcf)	$	$		$	$	
Oil and condensate (per Bbl)	71.96	66.75	8%	62.91	64.80	(3%)
Natural gas equivalent (per Mcfe)	11.99	11.12	8%	10.49	10.80	(3%)
Total:						
Natural gas (per Mcf)	$ 5.81	$ 6.21	(6%)	$ 6.38	$ 6.68	(4%)
Oil and condensate (per Bbl)	67.13	55.70	21%	58.26	54.54	7%
Natural gas equivalent (per Mcfe)	6.97	6.77	3%	7.07	7.11	(1%)

(1) Represent volumes sold regardless of when produced.

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(2) Average realized prices only include the effects of hedging contracts that are designated for hedge accounting. Had we included the effects of contracts not so designated, our average realized price for total gas would have been $7.52 and $7.06 per Mcf for the third quarter of 2007 and 2006, respectively, and $7.72 and $7.27 per Mcf for the nine months ended September 30, 2007 and 2006, respectively. Our total oil and condensate average realized price would have been $57.89 and $52.95 per Bbl for the third quarter of 2007 and 2006, respectively, and $52.83 and $52.19 per Bbl for the nine months ended September 30, 2007 and 2006, respectively. Without the effects of any

hedging contracts, our average realized prices for the third quarter of 2007 and 2006 would have been $5.81 and $6.19 per Mcf, respectively, for gas and $67.31 and $64.18 per Bbl, respectively, for oil. Our average realized prices, without the effects of hedging, for the nine months ended September 30, 2007 and 2006, would have been $6.38 and $6.63 per Mcf, respectively, for gas and $59.27 and $62.69 per Bbl, respectively, for oil.

Production. Our total natural gas and oil and condensate production (stated on a natural gas equivalent basis) for the third quarter of 2007 decreased 4% over the comparable period of 2006, while production for the nine months ended September 30, 2007 increased 12% over the comparable period of 2006. The third quarter of 2007 decrease was primarily due to the sale of substantially all of our properties in the Gulf of Mexico in early August 2007, partially offset by successful drilling efforts in the Mid-Continent, production resulting from the Rocky Mountain asset acquisition and increased liftings of production in Malaysia. The increase for the nine months ended September 30, 2007 was primarily due to successful drilling efforts in the Mid-Continent, the timing of liftings of production in Malaysia and China, the Rocky Mountain asset acquisition and the negative impact the Gulf of Mexico production deferrals related to the 2005 storms had in the first six months of 2006 (10 Bcfe). These increases were slightly offset by the sale of substantially all of our properties in the Gulf of Mexico in early August 2007.

Natural Gas. Our natural gas production for the third quarter of 2007 decreased 8% as compared to the same period of 2006, while natural gas production for the nine months ended September 30, 2007 increased 8% over the comparable period of 2006. The third quarter of 2007 decrease was primarily due to the sale of substantially all of our properties in the Gulf of Mexico, partially offset by successful drilling efforts in the Mid-Continent and production resulting from the Rocky Mountain asset acquisition. The increase for the nine month period of 2007 was primarily due to successful drilling efforts in the Mid-Continent, the Rocky Mountain asset acquisition and the 2006 Gulf of Mexico production deferrals mentioned above. These amounts were slightly offset by the sale of substantially all of our properties in the Gulf of Mexico.

Crude Oil and Condensate. Our third quarter of 2007 and nine months ended September 30, 2007 oil and condensate production increased 14% and 29%, respectively, compared to the same periods of 2006. The increases were the result of the timing of liftings of production in Malaysia and China (first lifting in China was in August 2006) and increased sales from our Monument Butte Field.

Operating Expenses. 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 third quarter of 2007 and 2006.

	Unit-of-Production (Per Mcfe) Three Months Ended September 30,		Percentage Increase (Decrease)	Amount (In millions) Three Months Ended September 30,		Percentage Increase (Decrease)
	2007	2006		2007	2006	
United States:						
Lease operating	$ 0.96	$ 0.54	78%	$ 54	$ 33	63%
Production and other taxes	0.35	0.14	150%	20	10	130%
Depreciation, depletion and amortization	2.69	2.55	5%	153	156	(2%)
General and administrative	0.61	0.51	20%	35	31	11%
Other		(0.09)	(100%)		(6)	(100%)
Total operating expenses	$ 4.61	$ 3.65	26%	$ 262	$ 224	17%
International:						
Lease operating	$ 3.30	$ 2.23	48%	$ 10	$ 3	221%
Production and other taxes	1.75	1.78	(2%)	5	2	114%
Depreciation, depletion and amortization	2.99	1.87	60%	9	3	246%
Ceiling test writedown		4.60	(100%)		6	(100%)
General and administrative	0.75	1.60	(53%)	2	2	1%
Total operating expenses	$ 8.79	$ 12.08	(27%)	$ 26	$ 16	58%
Total:						
Lease operating	$ 1.07	$ 0.58	84%	$ 64	$ 36	76%
Production and other taxes	0.42	0.18	133%	25	12	127%
Depreciation, depletion and amortization	2.71	2.54	7%	162	159	2%
Ceiling test writedown		0.10	(100%)		6	(100%)
General and administrative	0.62	0.53	17%	37	33	11%
Other		(0.09)	(100%)		(6)	(100%)
Total operating expenses	$ 4.82	$ 3.84	25%	$ 288	$ 240	20%

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Domestic Operations. Our domestic operating expenses for the third quarter of 2007, stated on an Mcfe basis, increased 26% over the same period of 2006. The period to period change was primarily related to the following items:

Lease operating expense (LOE) increased due to a $34 million ($0.55 per Mcfe) credit in the third quarter of 2006 resulting from the difference between the proceeds received from the settlement of all of our insurance claims related to the 2005 hurricanes and our hurricane related expenses. Without the impact of the insurance settlement in the third quarter of 2006, our LOE, on an Mcfe basis, would have decreased 19% during the third quarter of 2007 when compared to the same quarter of 2006 due to the sale of substantially all of our properties in the Gulf of Mexico, offset by higher operating costs for all of our operations.

Production and other taxes increased due to refunds of $8 million ($0.14 per Mcfe) related to production tax exemptions on certain of our onshore high cost gas wells recorded in the third quarter of 2006, an increase in the proportion of our production volumes subject to production taxes as a result of increased production from our Mid-Continent and Rocky Mountain operations, the sale of substantially all of our properties in the Gulf of Mexico and higher oil and condensate prices.

The increase in our depreciation, depletion and amortization (DD&A) rate resulted from higher cost reserve additions, offset by the proceeds from the sale of substantially all of our properties in the Gulf of Mexico and the sale of our coal bed methane assets in the Cherokee Basin. The cost of reserve additions was adversely impacted by escalating costs for drilling goods and services. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.03 per Mcfe for the third quarter of 2007 and $0.05 per Mcfe for the third quarter of 2006. The decrease in accretion expense is due to a significant reduction in our asset retirement obligation resulting from the sale of substantially all of our Gulf of Mexico properties.

General and administrative (G&A) expense increased primarily due to continued growth in our workforce. During the third quarter of 2007, we capitalized $12 million of direct internal costs as compared to $10 million in 2006.

In the third quarter of 2006, we recorded under the caption Operating expenses Other, a $6 million benefit related to our business interruption insurance coverage as a result of the operations disruptions from the 2005 storms.

International Operations. Our international operating expenses for the third quarter of 2007, stated on an Mcfe basis, decreased 27% over the same period of 2006. The decrease was primarily related to the ceiling test writedown of $6 million ($4.60 per Mcfe) associated with the discontinuation of our operations in Brazil recorded in the third quarter of 2006. Without the effects of the writedown, operating expenses for the third quarter of 2007, stated on an Mcfe basis, increased by 18%. The period to period change was primarily related to the following items:

LOE increased due to higher operating costs for our Malaysian operations.

While aggregate international liftings increased as the result of initial liftings from our Abu Field in Malaysia, production and other taxes on an Mcfe basis declined. Because of the additional capital we have invested in Malaysia, 2007 production has been subject to a lower tax rate per unit than it was during the comparable period of 2006.

DD&A increased as a result of higher cost reserve additions.

We recorded a ceiling test writedown of $6 million associated with ceasing our exploration efforts in Brazil in the third quarter of 2006.

G&A decreased due to initial production and liftings from our Abu field in Malaysia.

The following table presents information about our operating expenses for the first nine months of 2007 and 2006.

	Unit-of-Production (Per Mcfe)			Amount (In millions)		
	Nine Months Ended September 30,		Percentage Increase (Decrease)	Nine Months Ended September 30,		Percentage Increase (Decrease)
	2007	2006		2007	2006	
United States:						
Lease operating	$ 1.31	$ 0.85	54%	$ 245	$ 146	68%
Production and other taxes	0.28	0.20	40%	51	35	48%
Depreciation, depletion and amortization	2.77	2.50	11%	517	427	21%
General and administrative	0.56	0.50	12%	104	86	22%
Other		(0.06)	(100%)		(11)	(100%)
Total operating expenses	$ 4.92	$ 3.99	23%	$ 917	$ 683	34%
International:						
Lease operating	$ 2.69	$ 2.68		$ 23	$ 9	137%
Production and other taxes	1.40	2.23	(37%)	12	8	48%
Depreciation, depletion and amortization	2.65	1.76	51%	22	7	256%
Ceiling test writedown		1.75	(100%)		6	(100%)
General and administrative	0.36	0.91	(60%)	3	3	(5%)
Total operating expenses	$ 7.10	$ 9.33	(24%)	$ 60	$ 33	80%

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	Unit-of-Production (Per Mcfe) Nine Months Ended September 30, 2007	2006	Percentage Increase (Decrease)	Amount (In millions) Nine Months Ended September 30, 2007	2006	Percentage Increase (Decrease)
Total:						
Lease operating	$ 1.37	$ 0.89	54%	$ 268	$ 155	72%
Production and other taxes	0.32	0.24	33%	63	43	48%
Depreciation, depletion and amortization	2.76	2.48	11%	539	434	24%
General and administrative	0.55	0.51	8%	107	89	21%
Ceiling test writedown		0.04	(100%)		6	(100%)
Other		(0.06)	(100%)		(11)	(100%)
Total operating expenses	$ 5.00	$ 4.10	22%	$ 977	$ 716	37%

Domestic Operations. Our domestic operating expenses for the first nine months of 2007, stated on an Mcfe basis, increased 23% over the same period of 2006. The period to period change was primarily related to the following items:

LOE was adversely impacted by higher operating costs for all of our operations and repair expenditures of $53 million ($0.28 per Mcfe) related to the 2005 storms. Our 2006 LOE was impacted by a $34 million ($0.20 per Mcfe) credit resulting from the difference between the proceeds received in the third quarter of 2006 from the settlement of all of our insurance claims related to the 2005 hurricanes and our hurricane related expenses. Without the impact of the insurance settlement, our 2006 LOE would have been $1.05 per Mcfe.

Production and other taxes increased $0.08 per Mcfe as a result of increased production from our Mid-Continent and Rocky Mountain operations, which are subject to production taxes, and the sale of substantially all of our properties in the Gulf of Mexico, which were not subject to production taxes. In addition, during the first nine months of 2006, we recorded a benefit of $14 million ($0.08 per Mcfe) related to production tax exemptions on certain high cost gas wells, compared to a benefit of $5 million ($0.02 per Mcfe) recorded during the first nine months of 2007.

The increase in our DD&A rate resulted from higher cost reserve additions, offset by the proceeds from the sale of substantially all of our properties in the Gulf of Mexico and the sale of our coal bed methane assets in the Cherokee Basin. The cost of reserve additions was adversely impacted by escalating costs for drilling goods and services. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.04 per Mcfe for the first nine months of 2007 and $0.06 per Mcfe for the first nine months of 2006. The decrease in accretion expense is due to the significant reduction in our asset retirement obligation resulting from the sale of substantially all of our Gulf of Mexico properties.

G&A expense increased $0.06 per Mcfe primarily due to an increase in a litigation settlement reserve associated with a statewide royalty owner class action lawsuit in Oklahoma and continued growth in our workforce. During the first nine months of 2007, we capitalized $33 million of direct internal costs as compared to $29 million in 2006.

For the first nine months of 2006, we recorded under the caption Operating expenses Other, a $19 million redemption premium and an $8 million charge related to the unamortized original issue costs of our $250 million 8 3/8% senior subordinated notes that we redeemed in May 2006 and a $36 million benefit related to our business interruption insurance coverage as a result of the operations disruptions from the 2005 storms.

International Operations. Our international operating expenses for the first nine months of 2007, stated on an Mcfe basis, decreased 24% as compared to the same period of 2006. The decrease was primarily related to the ceiling test writedown of $6 million ($1.75 per Mcfe) associated with the discontinuation of our operations in Brazil recorded in the third quarter of 2006. Without the effects of the writedown, operating expenses for the first nine months of 2007, stated on an Mcfe basis, decreased by 6%. The period to period change was primarily related to the following items:

LOE increased due to higher operating costs for our Malaysian operations.

While aggregate international liftings increased as the result of initial liftings from our Abu Field in Malaysia and in China, production and other taxes on an Mcfe basis declined. Because of the additional capital we have invested in Malaysia, 2007 production has been subject to a lower tax rate per unit than it was during the comparable period of 2006. In addition, the production tax rate in China is lower, on an Mcfe basis, than the tax rate on our Malaysian production.

DD&A increased as a result of higher operating costs in Malaysia.

G&A expense decreased $0.55 per Mcfe due to increased liftings of production in Malaysia and China.

Interest Expense. The increase in interest expense for the third quarter and first nine months of 2007 resulted primarily from higher average debt levels outstanding under our credit arrangements as compared to the same periods of 2006.

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

	Three Month Period Ended September 30, 2007	Three Month Period Ended September 30, 2006	Nine Month Period Ended September 30, 2007	Nine Month Period Ended September 30, 2006
	(In millions)			
Cash flow hedges:				
Hedge ineffectiveness	$	$ (1)	$	$ 5
Other derivative contracts:				
Unrealized loss on discontinued cash flow hedges	(3)		(3)	
Unrealized gain (loss) due to change in fair market value	(20)	210	(211)	221
Realized gain on settlement	61	38	171	73
Total commodity derivative income (expense)	$ 38	$ 247	$ (43)	$ 299

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

Taxes. The effective tax rates for the third quarter of 2007 and 2006 were 40.2% and 36.9%, respectively. The effective tax rates for the nine months ended September 30, 2007 and 2006 were 38.8% and 36.6%, respectively. The effective tax rate for the first nine months of 2007 was greater than the federal statutory rate primarily due to $22 million of nondeductible expenses associated with certain of our international subsidiaries in a non-taxing international country. For a detailed reconciliation of our provision for income taxes to the federal statutory rate, see Note 13, Income Taxes, to our consolidated financial statements appearing earlier in this report.

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. We establish a capital budget at the beginning of each calendar year. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling.

We currently expect that our 2007 capital program (as adjusted for the purchase of the Rocky Mountain assets and the sale of substantially all of our Gulf of Mexico properties), together with the repayment of $125 million of our senior notes in October 2007, will exceed estimated cash flow from operations by approximately $1.4 billion. This shortfall has been made up with the proceeds from the sale of our Gulf of Mexico properties and the other completed dispositions described above. We are also considering the sale of our two producing fields in Bohai Bay, China.

Credit Arrangements. In June 2007, we entered into a new revolving credit facility that matures in June 2012. The facility provides for initial loan commitments of $1.25 billion from a syndicate of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments may be increased to a maximum aggregate amount of $1.65 billion if the current lenders increase their loan commitments or new financial institutions are added to the facility. Subject to compliance with covenants in our credit facility that restrict our ability to incur additional debt, we also have a total of $135 million of borrowing capacity under money market lines of credit with various banks. For a more detailed description of the terms of our credit arrangements, please see Note 5, Debt, to our consolidated financial statements appearing earlier in this report.

At October 24, 2007, we had no borrowings and undrawn letters of credit of $22 million under our credit facility and no borrowings under our money market lines and approximately $1.4 billion 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 and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital because our capital spending generally has exceeded our cash flows from operations and we generally use excess cash to pay down borrowings under our credit arrangements. We had a working capital deficit of $192 million as of September 30, 2007. This compares to a working capital deficit of $272 million as of December 31, 2006. The decrease in our working capital deficit at September 30, 2007 is primarily due to receipt of proceeds from the sale of substantially all of our Gulf of Mexico properties, partially offset by the change in the fair value of our commodity derivative instruments and their associated deferred taxes. At September 30, 2007, the fair value of our short-term derivatives was a net liability of $10 million compared to a net asset of $200 million at December 31, 2006.

Cash Flows from Operations. Cash flows from operations (both continuing and discontinued) 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 also have experienced fluctuations as a result of higher operating costs for all of our operations and the 2005 hurricanes.

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. During the first nine months of 2007, we incurred $53 million of repair expenditures in excess of the insurance benefits received. This amount is reflected as a use of operating cash flows for the nine months ended September 30, 2007.

We sell substantially all of our natural gas and oil production under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months. 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 $931 million for the nine months ended September 30, 2007, compared to $1,145 million for the same period in 2006. Even though our revenues plus realized gains on the settlement of our derivative contracts less our operating costs and interest expense increased 7%, our net cash flow from operations decreased 19% due to increased working capital requirements during the nine months ended September 30, 2007 compared to the same period of 2006. Our working capital requirements increased because of increased drilling activities, the timing of payments made by us to vendors and other operators and the timing and amount of advances received from our joint owners.

Capital Expenditures. Our capital spending for the first nine months of 2007 was $2,079 million, a 57% increase from our $1,325 million in capital spending during the same period of 2006. Of the $2,079 million, we invested $1,062 million in domestic exploitation and development, $182 million in domestic exploration (exclusive of exploitation and leasehold activity), $646 million for acquisitions and domestic leasehold activity (including $578 million for the Rocky Mountain assets acquired from Stone Energy) and $189 million internationally.

Our revised capital program for 2007 is $1.85 billion, excluding acquisitions. This total includes $50 million for continuing hurricane repairs in the Gulf of Mexico and excludes $130 million for capitalized interest and direct internal costs. Approximately 19% of the $1.85 billion is allocated to the Gulf of Mexico (including the shelf, the deep and ultra-deep shelf and deepwater), 21% to the onshore Gulf Coast, 37% to the Mid-Continent, 10% to the Rocky Mountains and 13% to international projects. We continue to pursue additional attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. 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 (both continuing and discontinued) for the nine months ended September 30, 2007 was $25 million. During the first nine months of 2007, we borrowed and repaid $2,909 million under our credit arrangements and received proceeds of $18 million from the issuance of shares of our common stock upon the exercise of stock options.

On October 15, 2007, our $125 million principal amount of 7.45% Senior Notes became due. We repaid the notes with cash on hand.

Net cash flow provided by financing activities for the nine months ended September 30, 2006 was $309 million. In April 2006, we issued $550 million aggregate principal amount of our 6 5/8% Senior Subordinated Notes due 2016. In May 2006, we used the proceeds from the offering to redeem $250 million principal amount of our 8 3/8% Senior Subordinated Notes due 2012. In addition, during the first nine months of 2006, we borrowed and repaid $491 million under our credit arrangements and received proceeds of $9 million from the issuance of shares of our common stock upon the exercise of stock options.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of September 30, 2007.

	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Bank revolving credit facility	$	$	$	$	$
Money market lines of credit					
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	529	76	143	122	188
Net derivative liabilities	166	11	141	14	
Asset retirement obligations	55	4	4	7	40
Operating leases	261	134	107	8	12
Deferred acquisition payments	9	3	4	2	
Oil and gas activities (1)	19				
Total other obligations	1,039	228	399	153	240
Total contractual obligations	$ 2,214	$ 353	$ 399	$ 328	$ 1,115

(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 September 30, 2007, these work related commitments totaled $19 million and were comprised of $6 million in the United States and $13 million internationally. These amounts are not included by maturity because their timing cannot be accurately predicted.

Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months to reduce our exposure to fluctuations in natural gas and oil prices. In the case of acquisitions, we may hedge acquired production for a longer period. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future 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, their use 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. With the sale of the Gulf of Mexico shelf production and the corresponding shift in the geographic distribution of our natural gas production, we have begun to utilize basis hedges to a greater degree.

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 that we receive for natural gas production in the Rocky Mountains, after basis differentials, transportation, and handling charges, has recently been as much as $5.30 per MMBtu less than the Henry Hub Index. In light of this potential risk with respect to our newly acquired Rocky Mountain assets, we have hedged the basis differential for a portion of our estimated production from proved reserves through 2012 at a weighted average of $1.18 less per MMBtu than the Henry Hub Index. The price we receive for our

Gulf Coast oil production typically averages about $2 per barrel below the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is 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, which generally is consistent with WTI. Oil sales from our operations in China typically sells at $7-$9 per barrel less than WTI.

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The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. At September 30, 2007, J Aron & Company, Bank of Montreal, JPMorgan Chase, Citibank, N.A. and Barclays Bank PLC were the counterparties with respect to 75% of our hedged future production.

Between September 30, 2007 and October 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
December 2007						
Price swap contracts	1,550	$8.23				
January 2008 March 2008						
Price swap contracts	4,550	8.23				
October 2008 December 2008						
Collar contracts	2,440		$8.00	$8.00	$ 10.17 $11.00	$10.56
January 2009 March 2009						
Collar contracts	3,600		8.00	8.00	10.17 11.00	10.56

In October 2007, we unwound the outstanding natural gas derivative contracts associated with our U.K. North Sea assets, which were sold in October 2007.

Please see the discussion and tables in Note 8, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing earlier in this report for a description of the accounting applicable to our hedging program and a listing of open contracts as of September 30, 2007 and the fair value of those contracts as of that date.

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 and source of capital resources to fund capital expenditures and our divestiture plans. Although we believe that these expectations 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;

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;
- the availability of refining capacity for the crude oil we produce from our Monument Butte Field;
- labor conditions; 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.

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Proved reserves. 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.

Ultra-deep shelf. We consider the ultra-deep shelf to be structures located on the shelf at depths of 20,000 feet and greater.

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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 generally and at the location of our production, 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. In addition we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We use hedging to reduce our exposure to fluctuations in natural gas and oil prices. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive 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. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. For a more detailed 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 8, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing earlier in this report.

Interest Rates

At September 30, 2007, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$
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 debt	$ 1,075	$ 100

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

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

(2) Classified as current debt on our consolidated balance sheet at September 30, 2007.

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

Foreign Currency Exchange Rates

The functional currency for all of our 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 September 30, 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 September 30, 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 third 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.

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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 alleged that we improperly reduced royalty payments for certain expenses and charges, and also claimed breach of contract and breach of fiduciary duties, among other claims. In April 2007, we entered into a settlement agreement that has recently received court approval.

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 September 30, 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	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under The Plans or Programs
July 1 July 31, 2007	106	$ 45.55		
August 1 August 31, 2007	1,205	48.50		
September 1 September 30, 2007	2,639	43.84		

(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.

Item 6. Exhibits

(a) Exhibits:

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

* Filed or furnished herewith.

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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: October 26, 2007

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

EXHIBIT INDEX

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