GOODRICH PETROLEUM CORP
Form 10-Q
August 09, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

For the Quarterly Period Ended June 30, 2006

OR

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

Commission file number: 001-7940

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

808 Travis, Suite 1320

Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(Registrant s telephone number, including area code): (713) 780-9494

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 x No ¨

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

Indicate by check mark whether the Registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ¨ No x

The number of shares outstanding of the Registrant s common stock as of August 4, 2006 was 24,962,966.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In Thousands, Except Share Amounts)

	June 30, 2006 (unaudited)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 4,081	$ 19,842
Accounts receivable, trade and other, net of allowance	8,899	6,397
Accrued oil and gas revenue	9,848	11,863
Fair value of interest rate derivatives	312	107
Prepaid expenses and other	973	463
Total current assets	24,113	38,672
Property and equipment:		
Oil and gas properties (successful efforts method)	460,750	316,286
Furniture, fixtures and equipment	1,308	1,075
	462,058	317,361
Less: Accumulated depletion, depreciation and amortization	(101,911)	(74,229)
Net property and equipment	360,147	243,132
Other assets:		
Restricted cash	2,039	2,039
Fair value of interest rate derivatives	459	
Deferred tax asset	3,602	11,580
Other	2,042	1,103
Total other assets	8,142	14,722
Total assets	$ 392,402	$ 296,526
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 55,359	$ 31,574
Accrued liabilities	17,966	15,973
Fair value of oil and gas derivatives	8,368	23,271
Accrued abandonment costs	92	92
Total current liabilities	81,785	70,910
Long-term debt	84,500	30,000
Accrued abandonment costs	8,855	7,868
Fair value of oil and gas derivatives	1,547	6,159
Total liabilities	176,687	114,937

Stockholders equity:		
Preferred stock: 10,000,000 shares authorized:		
Series A convertible preferred stock, $1.00 par value, 791,968 shares issued and outstanding at December 31, 2005		792
Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000 and 1,650,000 shares, respectively	2,250	1,650
Common stock: $0.20 par value, 50,000,000 shares authorized; issued and outstanding 24,947,133 and 24,804,737 shares, respectively	4,989	4,961
Additional paid in capital	209,912	187,967
Retained earnings (deficit)	2,703	(8,649)
Unamortized restricted stock awards		(2,066)
Accumulated other comprehensive loss	(4,139)	(3,066)
Total stockholders equity	215,715	181,589
Total liabilities and stockholders equity	$ 392,402	$ 296,526

See notes to consolidated financial statements

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In Thousands, Except Per Share Amounts)

(Unaudited)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Revenues:				
Oil and natural gas revenues	$ 29,334	$ 13,303	$ 54,239	$ 25,651
Other	1,292	238	1,638	713
	30,626	13,541	55,877	26,364
Operating expenses:				
Lease operating expense	4,670	2,288	8,254	4,532
Production taxes	1,631	971	3,215	1,757
Transportation	1,676	52	1,676	91
Depreciation, depletion and amortization	13,091	5,745	22,923	11,591
Exploration	1,870	2,418	3,364	3,942
General and administrative	4,195	1,805	7,966	3,425
Gain on sale of assets		(18)		(169)
Other	1,259	176	1,259	400
	28,392	13,437	48,657	25,569
Operating income	2,234	104	7,220	795
Other income (expense):				
Interest expense	(1,502)	(519)	(2,197)	(826)
Gain (loss) on derivatives not qualifying for hedge accounting	5,881	(269)	19,423	(10,112)
	4,379	(788)	17,226	(10,938)
Income (loss) before income taxes	6,613	(684)	24,446	(10,143)
Income tax (expense) benefit	(2,315)	239	(8,556)	3,547
Net income (loss)	4,298	(445)	15,890	(6,596)
Preferred stock dividends	1,512	158	2,993	316
Preferred stock redemption premium	9		1,545	
Net income (loss) applicable to common stock	$ 2,777	$ (603)	$ 11,352	$ (6,912)
Net income (loss) per share applicable to common stock:				
Basic	$ 0.11	$ (0.03)	$ 0.46	$ (0.31)
Diluted	$ 0.11	$ (0.03)	$ 0.45	$ (0.31)

Weighted average number of common shares:				
Basic	24,936	23,461	24,898	22,129
Diluted	25,446	23,461	25,406	22,129

See notes to consolidated financial statements

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

(Unaudited)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Cash flows from operating activities:		
Net income (loss)	$ 15,890	$ (6,596)
Adjustments to reconcile net income (loss) to net cash provided by operating activities -		
Depletion, depreciation and amortization	22,923	11,591
Unrealized (gain) loss on derivatives not qualifying for hedge accounting	(21,848)	10,333
Deferred income taxes	8,556	(3,547)
Dry hole costs	20	1,888
Amortization of leasehold costs	2,484	1,199
Stock based compensation	2,338	506
Gain on sale of assets		(169)
Other non cash items	401	75
Changes in assets and liabilities -		
Accounts receivable and other assets	(1,211)	579
Accounts payable and accrued liabilities	25,451	13,930
Net cash provided by operating activities	55,004	29,789
Cash flows from investing activities:		
Additions to oil and gas properties	(143,701)	(58,221)
Additions to furniture and fixtures	(233)	(130)
Proceeds from sale of assets	1,731	155
Net cash used in investing activities	(142,203)	(58,196)
Cash flows from financing activities:		
Net proceeds from Series B Preferred Stock offering	28,973	
Redemption of Series A Preferred Stock	(9,319)	
Net proceeds from common stock offering		53,175
Principal payments of bank borrowings	(3,000)	(46,000)
Proceeds from bank borrowings	57,500	19,000
Deferred financing costs		(187)
Exercise of stock options and warrants	40	477
Preferred stock dividends	(2,741)	(316)
Production payments		(235)
Other	(15)	
Net cash provided by financing activities	71,438	25,914
Decrease in cash and cash equivalents	(15,761)	(2,493)
Cash and cash equivalents, beginning of period	19,842	3,449
Cash and cash equivalents, end of period	$ 4,081	$ 956

Supplemental disclosures of cash flow information:				
Cash paid during the period for interest	$	1,468	$	742
Cash paid during the period for income taxes	$		$	30

See notes to consolidated financial statements

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In Thousands)

(Unaudited)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net income (loss)	$ 4,298	$ (445)	$ 15,890	$ (6,596)
Other comprehensive loss:				
Change in fair value of derivatives (1)	(1,096)	(1,215)	(2,175)	(4,380)
Reclassification adjustment (2)	690	1,042	1,102	2,463
Other comprehensive loss	(406)	(173)	(1,073)	(1,917)
Comprehensive income (loss)	$ 3,892	$ (618)	$ 14,817	$ (8,513)

(1) Net of income tax benefit of:	$ 590	$ 654	$ 1,171	$ 2,359
(2) Net of income tax expense of:	372	562	593	1,326

See notes to consolidated financial statements

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE A Basis of Presentation

The consolidated financial statements of Goodrich Petroleum Corporation (Goodrich or the Company or we) included in this Form 10-Q have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) and, accordingly, certain information normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States has been condensed or omitted. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Significant intercompany balances and transactions have been eliminated in consolidation. Certain reclassifications have been made to the prior year statements to conform to the current year presentation.

The accompanying consolidated financial statements of the Company should be read in conjunction with the consolidated financial statements and notes included in the Company s Annual Report on Form 10-K, as amended, for the year ended December 31, 2005. The results of operations for the six months ended June 30, 2006 are not necessarily indicative of the results to be expected for the full year.

NOTE B Recent Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (FASB) issued Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48), to clarify certain aspects of accounting for uncertain tax positions, including issues related to the recognition and measurement of those tax positions. This interpretation is effective for fiscal years beginning after December 15, 2006. We are in the process of evaluating the impact of the adoption of this interpretation on our consolidated financial position, results of operations or cash flows.

In March 2006, the FASB issued SFAS No.156, *Accounting for Servicing of Financial Assets* (SFAS 156), which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. The adoption of SFAS 156 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140* (SFAS 155). SFAS 155 clarifies certain issues relating to embedded derivatives and beneficial interests in securitized financial assets. The provisions of SFAS 155 are effective for all financial instruments acquired or issued after fiscal years beginning after September 15, 2006. We are currently assessing the impact that the adoption of SFAS 155 will have on our consolidated financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Paymen*t (SFAS 123R), replacing SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and superceding Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25). SFAS 123R requires recognition of share-based compensation in the financial statements. SFAS 123R was effective as of the first annual reporting period that began after June 15, 2005 and was adopted on January 1, 2006. See Note C for further details.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE C Stock-Based Compensation

Share-Based Employee Compensation Plans

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan), at our annual meeting of stockholders. The 2006 Plan is similar to and replaces our previously adopted 1995 Incentive Plan (the 1995 Plan) and 1997 Non-Employee Directors Stock Option Plan (the Directors Plan). No further awards will be granted under the previously adopted plans, however, those plans shall continue to apply to and govern awards made thereunder. Under the 2006 Plan, a maximum of 2.0 million new shares are reserved for issuance as awards of share options to officers, employees and non-employee directors. Share options granted to officers and employees will generally become exercisable in one-third increments over a three year period and to the extent not exercised, expire on the tenth anniversary of the date of grant. Share options granted to non-employee directors will usually be immediately exercisable and to the extent not exercised, expire on the tenth anniversary of the date of grant. The exercise price of share options granted under the 2006 Plan will equal the market value of the underlying stock on the date of grant. The 1995 Plan expired according to its original terms on August 16, 2005. However, on February 1, 2006, our Board of Directors approved the extension of the 1995 Plan through December 31, 2005 and the granting of a total of 101,129 shares of restricted stock and 525,000 stock options to certain of our employees and directors as of December 6, 2005, which was approved at our 2006 annual meeting of stockholders in May 2006. For accounting purposes, such restricted shares and options have been valued as of February 9, 2006, the date on which our directors and executive officers reached a level of more than 50% ownership of our common stock, so that shareholder approval of those actions was no longer uncertain.

Share options previously granted under the 1995 Plan become exercisable in one-third increments over a three year period and to the extent not exercised, expire on the tenth anniversary of the date of grant. Share options previously granted under the Directors Plan generally become exercisable immediately and expire, if not exercised, ten years thereafter. The exercise price of share options granted under the 1995 Plan and the Directors Plan equals the market value of the underlying stock on the date of grant. At June 30, 2006, options to purchase 100,000 shares of our common stock were outstanding under the 2006 Plan and options to purchase 979,500 shares of our common stock were outstanding under the 1995 Plan and the Directors Plan. In order to satisfy share option exercises, shares are issued from authorized but unissued common stock.

Adoption of New Accounting Pronouncement

Stock based compensation for the three and six months ended June 30, 2006 of $1.4 million and $2.3 million, respectively, has been recognized as a component of general and administrative expenses in the accompanying Consolidated Financial Statements.

Effective January 1, 2006 we adopted SFAS 123R, which required us to measure the cost of stock based compensation granted, including stock options and restricted stock, based on the fair market value of the award as of the grant date, net of estimated forfeitures. SFAS 123R supersedes SFAS 123 and APB 25. We adopted SFAS 123R using the modified prospective application method of adoption, which required us to record compensation cost related to unvested stock awards as of December 31, 2005 by recognizing the unamortized grant date fair value of these awards over the remaining service periods of those awards with no change in historical reported earnings. Awards granted after December 31, 2005 are valued at fair value in accordance with provisions of SFAS 123R and recognized on a straight line basis over the service periods of each award. We estimated forfeiture rates for all unvested awards based on our historical experience. The January 1, 2006 balance of unamortized restricted stock awards of $2.1 million was reclassified against additional paid-in-capital upon adoption of SFAS 123R. In fiscal 2006 and future periods, common stock par value will be recorded when the restricted stock is issued and additional paid-in-capital will be increased as the restricted stock compensation cost is recognized for financial reporting purposes.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Prior to 2006, we accounted for stock-based compensation in accordance with APB 25 using the intrinsic value method, which did not require that compensation cost be recognized for our stock options provided the option exercise price was established at 100% of the common stock fair market value on the date of grant. Under APB 25, we were required to record expense over the vesting period for the value of restricted stock granted. Prior to 2006, we provided pro forma disclosure amounts in accordance with SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* (SFAS 148), as if the fair value method defined by SFAS 123 had been applied to our stock-based compensation. Our net loss and net loss per share for the three and six months ended June 30, 2005 would have been greater if compensation cost related to stock options had been recorded in the financial statements based on fair value at the grant dates.

Pro forma net loss as if the fair value based method had been applied to all awards for the three and six months ended June 30, 2005 is as follows (in thousands, except per share amounts):

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net loss, as reported	$ (445)	$ (6,596)
Add: Stock based compensation programs recorded as expense, net of tax	171	329
Deduct: Total stock based compensation expense, net of tax	(278)	(542)
Pro forma net loss	$ (552)	$ (6,809)
Net loss applicable to common stock, as reported	$ (603)	$ (6,912)
Add: Stock based compensation programs recorded as expense, net of tax	171	329
Deduct: Total stock based compensation expense, net of tax	(278)	(542)
Pro forma net loss applicable to common stock	$ (710)	$ (7,125)
Net loss applicable to common stock per share:		
Basic and diluted as reported	$ (0.03)	$ (0.31)
Basic and diluted pro forma	$ (0.03)	$ (0.32)

The estimated fair value of the options granted during 2006 and prior years was calculated using a Black Scholes Merton option pricing model (Black Scholes). The following schedule reflects the various assumptions included in this model as it relates to the valuation of our options:

	June 30, 2006	December 31, 2005
Risk free interest rate	4.50 5.00%	6.00%
Weighted average volatility	54-57%	47%
Dividend yield	0%	0%
Expected years until exercise	5-6	5

The Black Scholes model incorporates assumptions to value stock-based awards. The risk-free rate of interest for periods within the expected term of the option is based on a zero-coupon U.S. government instrument over the expected term of the equity instrument. Expected volatility is based on the historical volatility of our common stock. We generally use the midpoint of the vesting period and the life of the grant to estimate employee option exercise timing (expected term) within the valuation model. This methodology is not materially different from our historical data on exercise timing. In the case of director options, we used historical exercise behavior. Employees and directors that have different historical exercise behavior with regard to option exercise timing and forfeiture rates are considered separately for valuation and attribution purposes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes the components of our stock-based compensation programs recorded as expense (in thousands):

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Restricted stock:				
Pretax compensation expense	$ 474	$ 263	$ 900	$ 506
Tax benefit	(166)	(92)	(315)	(177)
Restricted stock expense, net of tax	$ 308	$ 171	$ 585	$ 329
Stock options:				
Pretax compensation expense	$ 932	$	$ 1,438	$
Tax benefit	(326)		(503)	
Stock option expense, net of tax	$ 606	$	$ 935	$
Total share based compensation:				
Pretax compensation expense	$ 1,406	$ 263	$ 2,338	$ 506
Tax benefit	(492)	(92)	(818)	(177)
Total share based compensation expense, net of tax	$ 914	$ 171	$ 1,520	$ 329

As of June 30, 2006, $3.8 million and $8.0 million of total unrecognized compensation cost related to restricted stock and stock options, respectively, is expected to be recognized over a weighted average period of approximately 1.8 years for restricted stock and 2.2 years for stock options.

Option activity under our stock option plans as of June 30, 2006 and changes during the six months ended June 30, 2006 were as follows:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term In Years	Aggregate Intrinsic Value
Outstanding at January 1, 2006	519,500	$ 13.70		
Granted	625,000	24.10		
Exercised	(10,000)	4.00		
Forfeited	(55,000)	22.13		
Outstanding at June 30, 2006	1,079,500	$ 19.38	8.6	$ 9,727,023
Exercisable at June 30, 2006	372,833	$ 12.95	7.2	$ 5,757,889

The aggregate intrinsic value in the table above represents the total pre-tax intrinsic value (the difference between our closing stock price on the last trading day of the second quarter of 2006 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on June 30, 2006. The amount of aggregate intrinsic value will change based on the fair market value of our stock. The total intrinsic value of options exercised during the six months ended June 30, 2006 and 2005 was $233,000 and $772,300, respectively.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes information on unvested restricted stock outstanding as of June 30, 2006:

	Number of Shares	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2005	263,890	$ 11.13
Vested	(116,102)	7.80
Granted	109,629	23.70
Forfeited	(5,332)	20.78
Unvested at June 30, 2006	252,085	$ 17.93

In May 2006, an officer of the Company resigned and the Company accelerated the vesting of (1) options to purchase 10,000 shares and (2) 2,916 shares of previously unvested restricted stock that had been issued to the officer in 2004. The affected options are required to be accounted for as a modification of an award with a service vesting condition under SFAS 123R. The fair market value was calculated immediately prior to the modification and immediately after the modification to determine the incremental fair market value. This incremental value and the unamortized balance of the restricted stock resulted in the immediate recognition of compensation expense of approximately $0.1 million.

NOTE D Asset Retirement Obligations

SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets and requires that an asset retirement cost should be capitalized as part of the cost of the related long- lived asset and subsequently allocated to expense using a systematic and rational method. The reconciliation of the beginning and ending asset retirement obligation for the period ending June 30, 2006 is as follows (in thousands):

Beginning balance January 1, 2006	$ 7,960
Liabilities incurred	867
Liabilities settled	(75)
Accretion expense (reflected in depletion, depreciation and amortization expense)	195
Ending balance June 30, 2006	$ 8,947

NOTE E Long-Term Debt

Long-term debt consisted of the following balances (in thousands):

	June 30, 2006	December 31, 2005
Second lien term loan	$ 30,000	$ 30,000
Senior credit facility	54,500	
Less current maturities		
Total long-term debt	$ 84,500	$ 30,000

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On November 17, 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Amended and Restated Credit Agreement) and a funded $30.0 million second lien term loan (the Second Lien Term Loan Agreement) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Amended and Restated Credit Agreement were increased from $50.0 million to $200.0 million and the maturity was extended from February 25, 2008 to February 25, 2010. Revolving borrowings under the Amended and Restated Credit Agreement are subject to periodic redeterminations of the borrowing base which is currently established at $105.0 million, and is currently scheduled to be redetermined in the third quarter of 2006, based upon our 2006 internally prepared mid-year reserve report. With a portion of the net proceeds of the offering of our 5.375% Series B Cumulative Convertible Preferred Stock (the Series B Convertible Preferred Stock) in December 2005, we fully repaid all outstanding indebtedness on our revolver in the amount of $47.5 million leaving a zero balance outstanding as of December 31, 2005. Interest on revolving borrowings under the Amended and Restated Credit Agreement accrues at a rate calculated, at our option, at either the bank base rate plus 0.00% to 0.50%, or LIBOR plus 1.25% to 2.00%, depending on borrowing base utilization. BNP Paribas (BNP) is the lead lender and administrative agent under the amended credit facility with Comerica Bank and Harris Nesbit Financing, Inc. as co-lenders.

The terms of the Amended and Restated Credit Agreement require us to maintain certain covenants. The covenants include**:**

Current Ratio of 1.0/1.0;

Interest Coverage Ratio which is not less than 3.0/1.0 for the trailing four quarters, and

Tangible Net Worth of not less than $53,392,838, plus 50% of cumulative net income after September 30, 2004, plus 100% of the net proceeds of any subsequent equity issuance.

As of June 30, 2006, we were in compliance with all of the financial covenants of the Amended and Restated Credit Agreement.

The Second Lien Term Loan Agreement provides for a 5-year, non-revolving loan of $30.0 million which was funded on November 17, 2005 and is due in a single maturity on November 17, 2010. Optional prepayments of term loan principal can be made in amounts of not less than $5.0 million during the first year at a 1% premium and without premium after the first year. Interest on term loan borrowings accrues at a rate calculated, at our option, at either base rate plus 3.50%, or LIBOR plus 4.50%, and is payable quarterly. BNP is the lead lender and administrative agent under the Second Lien Term Loan Agreement.

The terms of the Second Lien Term Loan Agreement require us to maintain certain covenants. Capitalized terms are defined in the loan agreement. The covenants include:

Total Debt to EBITDAX Ratio which is not greater than 4.0/1.0 for the most recent period of four fiscal quarters for which financial statements are available and

Asset Coverage Ratio to be not less than 1.5/1.0.

As of June 30, 2006, we were in compliance with all of the financial covenants of the Second Lien Term Loan Agreement.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE F Preferred Stock

In December 2005, 1,650,000 shares of our Series B Convertible Preferred Stock were issued in a private placement for net proceeds of $79.8 million (after offering costs of $2.7 million). On January 23, 2006, the initial purchasers exercised their option to purchase an additional 600,000 shares of Series B Convertible Preferred Stock at the same price per share, resulting in net proceeds of $29.0 million.

As part of this transaction we filed a registration statement with the SEC on April 20, 2006 for the purpose of registering the resale of the shares of common stock issuable pursuant to the purchase agreement. The registration statement was declared effective by the SEC on August 9, 2006.

During the first quarter of 2006 we completed the redemption of our Series A Convertible Preferred Stock. Of the previously outstanding shares of Series A Convertible Preferred Stock, holders of 15,539 shares elected to convert such shares into a net total of 6,466 shares of our common stock and the remaining shares were redeemed in cash for $12 per share, plus accrued dividends. The total redemption cost to us was approximately $9.3 million and was funded from available cash resources. This amount includes a $1.5 million redemption premium which is treated in the same manner as preferred stock dividends on the Consolidated Statement of Operations.

NOTE G Net Income (Loss) Per Share

Net income (loss) applicable to common stock was used as the numerator in computing basic and diluted income (loss) per common share for the three and six months ended June 30, 2006 and 2005. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Weighted average shares outstanding basic	24,936	23,461	24,898	22,129
Effect of dilutive securities stock options and restricted stock	316		314	
Effect of dilutive securities warrants	194		194	
Weighted average shares outstanding diluted	25,446	23,461	25,406	22,129

NOTE H Hedging Activities

Commodity Hedging Activity

We enter into swap contracts, costless collars or other hedging agreements from time to time to manage the commodity price risk for a portion of our production. We consider these to be hedging activities and, as such, monthly settlements on these contracts are reflected in our crude oil and natural gas sales, provided the contracts are deemed to be effective hedges under FAS 133. Our strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our production. As of June 30, 2006, the commodity hedges we utilized were in the form of: (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. Hedge ineffectiveness results from differences between the NYMEX contract terms and the physical location, grade and quality of our oil and gas production.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of June 30, 2006, our open forward position on our outstanding commodity hedging contracts was as follows:

Swaps	Volume	Average Price
Natural gas (MMBtu/day)		
3Q 2006	15,000	$ 6.95
4Q 2006	15,000	6.95
1Q 2007	10,000	7.77
Oil (Bbl/day)		
3Q 2006	800	$50.80
4Q 2006	800	50.80
2007	400	53.35

Collars	Volume	Average Floor/Cap	
Natural gas (MMBtu/day)			
1Q 2007	25,000	$7.00	$14.92
2Q 2007	30,000	7.00	14.75
3Q 2007	30,000	7.00	14.75
4Q 2007	30,000	7.00	14.75
Oil (Bbl/day)			
2007	400	$60.00	$76.50

The fair value of the oil and gas hedging contracts in place at June 30, 2006 resulted in a net liability of $9.9 million. As of June 30, 2006, $3.3 million (net of $1.8 million in income taxes) of deferred losses on derivative instruments accumulated in other comprehensive loss are expected to be reclassified into earnings during the next twelve months. For the six months ended June 30, 2006, $0.7 million of previously deferred losses (net of $0.4 million in income taxes) was reclassified out of accumulated other comprehensive loss as the cash flow settlement of the hedged items was recognized in earnings. For the six months ended June 30, 2006, we recognized in earnings a gain on derivatives not qualifying for hedge accounting in the amount of $19.4 million which includes $2.4 million in settlement payments on ineffective gas hedges and a $0.5 million gain on interest rate derivatives. This unrealized gain was recognized because our gas swaps have been deemed ineffective since the fourth quarter of 2004, and accordingly, the changes in fair value of such hedges could no longer be reflected in other comprehensive loss. In addition, all of our collars did not qualify for hedge accounting treatment and those changes in fair value have been recognized in earnings.

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Domestic crude oil and gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Interest Rate Swaps

We have variable-rate debt obligations that expose us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. At June 30, 2006 we had the following interest rate swaps in place with BNP (in millions):

Effective Date	Maturity Date	LIBOR Swap Rate	Notional Amount
02/27/06	02/26/07	4.08%	$ 23.0
02/27/06	02/26/07	4.85%	17.0
02/26/07	02/26/09	4.86%	40.0

The fair value of the interest rate swap contracts in place at June 30, 2006, resulted in an asset of $0.8 million. As of June 30, 2006, $153,000 (net of $82,000 in income taxes) of deferred net gains on derivative instruments accumulated in other comprehensive income are expected to be reclassified into earnings during the next twelve months.

We entered into two interest rate swaps to protect against movements in interest rates during the fourth quarter of 2005. The documentation was not prepared at the time of inception for these hedges and as a result, we were not entitled to apply hedge accounting to these instruments. The failure to qualify for hedge accounting requires that all changes in the fair value of the interest rate swap be recorded in the consolidated statements of operations. Accordingly, for the six months ended June 30, 2006, we recognized in earnings a gain of approximately $0.5 million, which is included in the aforementioned total gain of $19.4 million.

NOTE I Commitments and Contingencies

In July 2005, we received a Notice of Proposed Tax Due from the State of Louisiana asserting that we underpaid our Louisiana franchise taxes for the years 1998 through 2004 in the amount of $0.5 million. The Notice of Proposed Tax Due includes additional assessments of penalties and interest in the amount of $0.4 million for a total asserted liability of $0.9 million. We believe that we have fully paid our Louisiana franchise taxes for the years in question; therefore, we intend to vigorously contest the Notice of Proposed Tax Due. We have commenced our analysis of this contingency and have not recorded any provision for possible payment of additional Louisiana franchise taxes nor any related penalties and interest.

We are party to additional lawsuits arising in the normal course of business. We intend to defend these actions vigorously and believe, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our financial position or results of operations.

NOTE J Disposition of Assets

In June 2006, we assigned 50% of our interest solely in the deep rights in our Cotton prospect in East Texas, defined as rights below the top of the Knowles Lime formation at 12,901 below the surface, while reserving all of our rights to and above the Upper, Middle and Lower Travis Peak section in approximately 20,500 net acres for approximately $1.6 million. We had received one-half of the sales price as of June 30, 2006 and one-half has been recorded as a receivable in the consolidated financial statements. Pursuant to the agreement, within 18 months of the assignment, the assignee will either pay all of our share of drilling costs to a depth of 16,500 feet in a well (the carried well) drilled on the acreage or pay us a non participation fee of $4.0 million should no well be drilled. The transaction was accounted for as a recovery of cost.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Overview

General

We are an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the Cotton Valley trend of East Texas and Northwest Louisiana and in the transition zone of South Louisiana.

Our business strategy is to provide long term growth in net asset value per share, through the growth and expansion of our oil and gas reserves and production. We focus on adding reserve value through the development of our relatively low risk development drilling program in the Cotton Valley trend, while maintaining our drilling activities in select high impact well locations in South Louisiana. We continue to aggressively pursue the acquisition and evaluation of prospective acreage, oil and gas drilling opportunities and potential property acquisitions.

Source of Revenue

We derive our revenues from the sale of oil and natural gas that is produced from our properties. Revenues are a function of both the volume produced and the prevailing market price at the time of sale. Production volumes, while somewhat predictable after wells have begun producing, can be impacted for various reasons. Hurricanes Katrina and Rita in the third quarter of 2005 are an example of how production volumes can be impacted to defer volumes from the current period to future periods. The price of oil and natural gas is a primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a portion of our oil and natural gas production. While the derivative instruments may protect downward price fluctuation, the use of certain types of derivative instruments may prevent us from realizing the full benefit of upward price movements.

Second Quarter 2006 Highlights

Production and Revenue Growth

- We increased our oil and gas production volumes to approximately 43,700 Mcfe per day, representing over a 100% increase from the second quarter of 2005 and an increase of approximately 20%, on a sequential basis, from the first quarter of 2006.

- Oil and gas revenues increased 107% from the second quarter of 2005 and 19% sequentially from the first quarter of 2006.

Drilling Activity

- We had drilling operations on 31 gross wells during the second quarter of 2006.

Cotton Valley Trend

- As of June 30, 2006, we had drilled 107 wells in the Cotton Valley trend resulting in a 100% success rate.

- Cotton Valley trend volumes increased to 75% of total volumes in the second quarter of 2006 as compared to 60% of total volumes in the first quarter of 2006.

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A more complete overview and discussion of our operations can be found in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2005 Form 10-K, as amended.

Hurricanes Katrina and Rita Update

In August and September 2005, Hurricanes Katrina and Rita caused damage to our assets on the Gulf Coast, significantly on one producing well (Norton) and offshore facilities in our Burrwood/West Delta 83 field. As of June 30, 2006, our share of hurricane related costs in these fields is approximately $6.8 million and we have received and accrued proceeds of $4.2 million. We anticipate that we will ultimately receive reimbursement for all but $0.9 million of our remaining insured losses, which represents our deductible and amounts exceeding insurance limits, $0.4 million of which has been expensed in 2006.

As claims are submitted to the insurance companies, they are reviewed and preliminary payments made until all losses are incurred and documented. A final payment will be made once we and our insurers agree on the total measurement value of the claim, which is expected sometime during the third quarter of 2006.

Results of Operations

Three Months Ended June 30, 2006 Compared to Three Months Ended June 30, 2005

For the three months ended June 30, 2006, we reported net income applicable to common stock of $2.8 million, or $0.11 per basic share on total revenue of $30.6 million as compared with a net loss applicable to common stock of $0.6 million, or $0.03 per basic share, on total revenue of $13.5 million for the three months ended June 30, 2005.

Oil and Natural Gas Revenues

Revenues presented in the table and the discussion below represent revenue from sales of our oil and natural gas production volumes and include the realized gains and losses on the effective portion of our derivative instruments as further described under Note H to the Consolidated Financial Statements.

	Three Months Ended June 30,		% Change from 2005
	2006	2005	to 2006
Production:			
Natural gas (MMcf)	3,295	1,194	176%
Oil and condensate (MBbls)	113	128	(12)%
Total (MMcfe)	3,974	1,962	103%
Revenues from production (in thousands):			
Natural gas	$ 22,765	$ 8,523	167%
Effects of cash flow hedges			
Total	$ 22,765	$ 8,523	167%
Oil and condensate	$ 7,740	$ 6,224	24%
Effects of cash flow hedges	(1,171)	(1,444)	(19)%
Total	$ 6,569	$ 4,780	37%
Natural gas, oil and condensate	$ 30,505	$ 14,747	107%
Effects of cash flow hedges	(1,171)	(1,444)	(19)%
Total revenues from production	$ 29,334	$ 13,303	121%

Table continued on following page

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	% Change from 2005 to 2006
Average sales price per unit:			
Natural gas (per Mcf)	$ 6.91	$ 7.14	(3)%
Effects of cash flow hedges (per Mcf)			
Total (per Mcf)	$ 6.91	$ 7.14	(3)%
Oil and condensate (per Bbl)	$ 68.39	$ 48.63	41%
Effects of cash flow hedges (per Bbl)	(10.35)	(11.28)	(8)%
Total (per Bbl)	$ 58.04	$ 37.35	55%
Natural gas, oil and condensate (per Mcfe)	$ 7.68	$ 7.51	2%
Effects of cash flow hedges (per Mcfe)	(0.29)	(0.74)	(60)%
Total (per Mcfe)	$ 7.39	$ 6.77	9%

Excluding the effects of settled derivatives, revenues from production increased 107% in the second quarter of 2006 compared to the same period in 2005 due primarily to a substantial increase in Cotton Valley trend production. Revenues were also impacted favorably by a 2% increase in our sales price per unit.

Other. We own an approximate 2.5% working interest in the Yscloskey gas processing plant in South Louisiana. As a plant owner, we retain that same percentage of natural gas liquid (NGL) revenue extracted from third party gas as a fee for the services provided by the plant. In addition, some third party non-plant owners that process their gas at Yscloskey are required to pay the plant owners a monetary processing fee. We retain our 2.5% share of this fee. For the three months ended June 30, 2006, other revenue includes $1.1 million of such plant related revenues. The plant sustained extensive damage during Hurricane Katrina and normal operations did not resume until late June 2006.

Lease Operating. Lease operating expenses (LOE) for the second quarter of 2006 increased to $4.7 million ($1.18 per Mcfe) from $2.3 million ($1.17 per Mcfe) in the second quarter of 2005. This increase was primarily attributable to the aforementioned increase in production. Also contributing to this increase is an additional loss of $0.4 million of hurricane related costs that will not be covered by insurance reimbursement and $0.3 million of additional abandonment costs related to outside operated wells.

Production Taxes. Production taxes increased to $1.6 million for the second quarter of 2006 compared to $1.0 million for the comparable period in 2005 due to an increase in production volumes and product prices. Most of our Cotton Valley trend wells qualify for the Tight Gas Sands credit allowed for severance tax in the State of Texas. While we have only reflected credits on wells that have been approved by the State, we anticipate that we will incur a gradually lower production tax rate in the future as we add further Cotton Valley wells to our production base and as reduced rates are approved and credits are received.

Transportation. Emerging Issues Task Force Issue 00-10, *Accounting for Shipping and Handling Fees and Costs* (EITF 00-10), requires that transportation expenses be shown as an expense in the statement of operations and not deducted from revenues. Transportation costs of $1.7 million for the three months ended June 30, 2006 includes the reclassification of $0.5 million of costs previously classified in the first quarter of 2006 as a deduction from oil and gas revenues in that quarter. The increase in 2006 compared to 2005 is primarily due to increased production in our Cotton Valley Trend and the utilization of different marketing arrangements.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) expense increased to $13.0 million from $5.7 million for the same period in 2005 primarily due to higher levels of production. The average DD&A rate increased to $3.29 per Mcfe in the second quarter of 2006 compared to $2.93 per Mcfe in the same quarter of 2005 due to a higher percentage of production coming from fields with higher average DD&A rates.

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Exploration. Exploration expense for the second quarter of 2006 decreased to $1.9 million compared to $2.4 million for the second quarter of 2005. This decrease was primarily due to the fact that we incurred no dry hole costs in 2006 while incurring $1.6 million in dry hole costs in the second quarter of 2005.

General and Administrative. General and administrative expense increased to $4.2 million for the second quarter of 2006 compared to $1.8 million for the same period of 2005. This increase was primarily due to the implementation of SFAS 123R which increased non cash stock based compensation expense by $1.1 million from the second quarter of 2005 due to expensing the fair value of stock options granted. See Note C to the Consolidated Financial Statements for more information. In addition, an approximate 40% increase in the number of employees at June 30, 2006 versus June 30, 2005 generated higher compensation related costs.

Other. We own an approximate 2.5% working interest in the Yscloskey gas processing plant in South Louisiana. As a plant owner, we share in the costs of operating the plant. For the three months ended June 30, 2006, we recorded $1.2 million of such plant related expenses. The plant sustained extensive damage during Hurricane Katrina and normal operations resumed in late June 2006.

Interest Expense. Interest expense increased to $1.5 million from the second quarter 2005 amount of $0.5 million as a result of a higher average interest rate and higher borrowings in the second quarter of 2006.

Gain (Loss) on Derivatives Not Qualifying for Hedge Accounting. Gain on derivatives not qualifying for hedge accounting was $5.9 million for the second quarter of 2006 compared to a loss of $0.3 million for the second quarter of 2005. The gain in 2006 includes an unrealized gain of $5.4 million for the changes in fair value of our ineffective oil and gas hedges, and a realized gain of $0.2 million for the effect of settled derivatives on our ineffective gas hedges. Our natural gas hedges were deemed ineffective, beginning in the fourth quarter of 2004, and we have been required to reflect the changes in the fair value of our natural gas hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. Also included in the 2006 amount is an unrealized gain of $0.3 million related to interest rate swaps that did not qualify for hedge accounting treatment. To the extent that our hedges do not qualify for hedge accounting in the future, we will likewise be exposed to volatility in earnings resulting from changes in the fair value of our hedges.

Income taxes. Income taxes were a non cash expense of $2.3 million for the second quarter of 2006 compared to a benefit of $0.2 million for the second quarter of 2005. The amounts in both periods essentially represented 35% of pre-tax income (loss). We did not however, incur any income taxes on a current basis due to our substantial tax net operating loss carrryforwards and significant drilling activity.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

For the six months ended June 30, 2006, we reported net income applicable to common stock of $11.4 million, or $0.46 per basic share on total revenue of $55.9 million as compared with a net loss applicable to common stock of $6.9 million, or $0.31 per basic share, on total revenue of $26.4 million for the six months ended June 30, 2005.

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Oil and Natural Gas Revenues

Revenues presented in the table and the discussion below represent revenue from sales of our oil and natural gas production volumes and include the realized gains and losses on the effective portion of our derivative instruments as further described under Note H to the Consolidated Financial Statements.

	Six Months Ended June 30,		% Change from 2005
	2006	**2005**	**to 2006**
Production:			
Natural gas (MMcf)	5,915	2,520	135%
Oil and condensate (MBbls)	224	226	(1)%
Total (MMcfe)	7,261	3,876	87%
Revenues from production (in thousands):			
Natural gas	$ 41,429	$ 17,060	145%
Effects of cash flow hedges			
Total	$ 41,429	$ 17,060	145%
Oil and condensate	$ 14,732	$ 11,243	31%
Effects of cash flow hedges	(1,922)	(2,652)	(28)%
Total	$ 12,810	$ 8,591	49%
Natural gas, oil and condensate	$ 56,161	$ 28,303	98%
Effects of cash flow hedges	(1,922)	(2,652)	(28)%
Total revenues from production	$ 54,239	$ 25,651	111%
Average sales price per unit:			
Natural gas (per Mcf)	$ 7.01	$ 6.77	3%
Effects of cash flow hedges (per Mcf)			
Total (per Mcf)	$ 7.01	$ 6.77	3%
Oil and condensate (per Bbl)	$ 65.64	$ 49.73	32%
Effects of cash flow hedges (per Bbl)	(8.57)	(11.73)	(27)%
Total (per Bbl)	$ 57.07	$ 38.00	50%
Natural gas, oil and condensate (per Mcfe)	$ 7.73	$ 7.30	6%
Effects of cash flow hedges (per Mcfe)	(0.26)	(0.68)	(61)%
Total (per Mcfe)	$ 7.47	$ 6.62	13%

Excluding the effects of settled derivatives, revenues from production increased 98% in the first half of 2006 compared to the same period in 2005 due primarily to a substantial increase in Cotton Valley trend production. Revenues were also impacted favorably by a 6% increase in our sales price per unit.

Other. We own an approximate 2.5% working interest in the Yscloskey gas processing plant in South Louisiana. As a plant owner, we retain that same percentage of natural gas liquid (NGL) revenue extracted from third party gas as a fee for the services provided by the plant. In addition, some third party non-plant owners that process their gas at Yscloskey are required to pay the plant owners a monetary processing fee. We retain our 2.5% share of this fee. For the first half of 2006, other revenue includes $1.1 million of such plant related revenues. The plant sustained extensive damage during Hurricane Katrina and normal operations resumed in late June 2006.

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Lease Operating. Lease operating expenses for the first half of 2006 increased to $8.3 million ($1.14 per Mcfe) from $4.5 million ($1.17 per Mcfe) in the first half of 2005. This increase was primarily attributable to the aforementioned increase in production. Also contributing to this increase is an additional loss of $0.4 million of hurricane related costs that will not be covered by insurance reimbursement, $0.3 million of additional abandonment costs related to outside operated wells and the uninsured portion of costs for an oil spill that occurred from a non-producing well in our Plumb Bob field on March 21, 2006. The spill of an estimated 2,000 barrels of oil was quickly contained and the costs of site restoration less our deductible will be covered by our insurance.

Production Taxes. Production taxes increased to $3.2 million for the first half of 2006 compared to $1.8 million for the comparable period in 2005 due to an increase in production volumes and product prices. Most of our Cotton Valley trend wells qualify for the Tight Gas Sands credit allowed for severance tax in the State of Texas. While we have only reflected credits on wells that have been approved by the State, we anticipate that we will incur a gradually lower production tax rate in the future as we add further Cotton Valley wells to our production base and as reduced rates are approved and credits are received.

Transportation. EITF 00-10 requires that transportation expenses be shown as an expense in the statement of operations and not deducted from revenues. Transportation costs of $1.7 million in the first half of 2006 relate primarily to our Cotton Valley trend and increased compared to the same period in 2005 due to increased production in our Cotton Valley trend and the utilization of different marketing arrangements.

Depreciation, Depletion and Amortization. DD&A expense increased to $22.9 million in the first half of 2006 from $11.6 million for the same period in 2005 primarily due to higher levels of production. The average DD&A rate increased to $3.16 per Mcfe in the first half of 2006 compared to $2.99 per Mcfe in the same period in 2005 due to a higher percentage of production coming from fields with higher average DD&A rates.

Exploration. Exploration expense for the first half of 2006 decreased to $3.4 million compared to $3.9 million for the first half of 2005. This decrease was primarily due to the fact that we incurred no dry hole costs in 2006 while incurring $1.9 million in dry hole costs in the first half of 2005. Partially offsetting this decrease was an increase in leasehold amortization.

General and Administrative. General and administrative expense increased to $8.0 million for the first half of 2006 compared to $3.4 million for the same period of 2005. This increase was primarily due to the implementation of SFAS 123R which increased non cash stock based compensation expense by $1.8 million from the first half of 2005 due to expensing the fair value of stock options granted. See Note C to the Consolidated Financial Statements for more information. In addition, an approximate 40% increase in the number of employees at June 30, 2006 versus June 30, 2005 generated higher compensation related costs.

Other. We own an approximate 2.5% working interest in the Yscloskey gas processing plant in South Louisiana. As a plant owner, we share in the costs of operating the plant. For the first half of 2006, we recorded $1.2 million of such plant related expenses. The plant sustained extensive damage during Hurricane Katrina and normal operations resumed in late June 2006.

Interest Expense. Interest expense increased to $2.2 million from the first half 2005 amount of $0.9 million as a result of a higher average interest rate and higher borrowings in the first half of 2006.

Gain (Loss) on Derivatives Not Qualifying for Hedge Accounting. Gain on derivatives not qualifying for hedge accounting was $19.4 million for the first half of 2006 compared to a loss of $10.1 million for the first half of 2005. The gain in 2006 includes an unrealized gain of $21.3 million for the changes in fair value of our ineffective oil and gas hedges, and a realized loss of $2.4 million for the effect of settled derivatives on our ineffective gas hedges. Our natural gas hedges were deemed ineffective, beginning in the fourth quarter of 2004, and we have been required to reflect the changes in the fair value of our natural gas hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. Also included in the 2006 amount is an unrealized gain of $0.5 million related to interest rate swaps that did not qualify for hedge accounting treatment. To the extent that our hedges do not qualify for hedge accounting in the future, we will likewise be exposed to volatility in earnings resulting from changes in the fair value of our hedges.

Income taxes. Income taxes were a non cash expense of $8.6 million for the first half of 2006 compared to a benefit of $3.5 million for the first half of 2005. The amounts in both periods essentially represented 35% of pre-tax income (loss). We did not however, incur any income taxes on a current basis due to our substantial tax net operating loss carrryforwards and significant drilling activity.

Liquidity and Capital Resources

Cash Flows

Operating activities. Net cash provided by operating activities increased to $55.0 million, up 85% from $29.8 million in the first half of 2005. The increase was a result of an increase in production levels and natural gas and crude oil prices in the first half of 2006 compared to the first half of 2005, partially offset by increases in lease operating expenses and general and administrative expenses. Excluding the effect of settled derivatives, sales of oil and gas increased $27.9 million in the first half of 2006 compared to the same period in 2005, with realized oil and natural gas prices increasing 6% from the first half of 2005. Production volumes increased 87% in the first half of 2006 compared to the first half of 2005. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in adjustments to our operating cash flow in the amounts of $24.2 million and $14.5 million in the six months ended June 30, 2006 and 2005, respectively, primarily reflecting increased revenue and expenditure activity associated with our Cotton Valley trend wells.

Investing activities. Net cash used in investing activities was $142.2 million for the first half of 2006 compared to $58.2 million for the first half of 2005. For the six months ended June 30, 2006, additions to oil and gas properties totaled $143.7 million primarily due to accelerated development of our Cotton Valley trend, which accounted for 89% of the capital costs incurred in the first half of 2006. We conducted drilling operations on approximately 57 gross wells, of which 51 were located in our Cotton Valley trend, during the first half of 2006. We also received proceeds of $1.7 million from the sale of two salt water disposal wells and the sale of a partial interest in deep rights in the Cotton prospect in East Texas.

Financing activities. Net cash provided by financing activities was $71.4 million for the first half of 2006 compared to $25.9 million for the first half of 2005. On January 23, 2006, the initial purchasers of our 5.375% Series B Cumulative Convertible Preferred Stock (the Series B Convertible Preferred Stock) exercised their over-allotment option to purchase an additional 600,000 shares at the same price per share, resulting in net proceeds of $29.0 million. In February 2006, we fully redeemed all issued and outstanding shares of our Series A Convertible Preferred Stock at a cost of approximately $9.3 million. Financing activities also included net borrowings of $54.5 million under our senior revolver, resulting in amounts outstanding and borrowing availability under this facility of $54.5 million and $50.5 million, respectively, at June 30, 2006. Subsequent to the issuance of the Series B Convertible Preferred Stock, we have approximately $37.5 million of securities available for issue under the current shelf registration statement.

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In May 2006, our Board of Directors approved a preliminary 2006 capital expenditure budget of approximately $220.0 million, of which approximately 85% is expected to be focused on the relatively low risk development drilling program in the Cotton Valley trend of East Texas and Northwest Louisiana and the remainder on our existing properties and new exploration programs in South Louisiana. Our Board may increase our capital expenditure budget for 2006, subject to future economic conditions and financial resources. We expect to finance our 2006 capital expenditures through a combination of cash flow from operations and borrowings under our existing bank credit facility (see Senior Credit Facility and Term Loan). In the future, we may issue additional debt or equity securities to provide additional financial resources for our capital expenditures and other general corporate purposes. Our senior credit facility and term loan include certain financial covenants with which we were in compliance as of June 30, 2006. We do not anticipate a lack of borrowing capacity under our senior credit facility or term loan in the foreseeable future due to an inability to meet any such financial covenants nor a reduction in our borrowing base.

Senior Credit Facility and Term Loan

On November 17, 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Amended and Restated Credit Agreement) and a funded $30.0 million second lien term loan (the Second Lien Term Loan Agreement) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Amended and Restated Credit Agreement were increased from $50.0 million to $200.0 million and the maturity was extended from February 25, 2008 to February 25, 2010. Revolving borrowings under the Amended and Restated Credit Agreement are subject to periodic redeterminations of the borrowing base which is currently established at $105.0 million, and is currently scheduled to be redetermined in the third quarter of 2006, based upon our 2006 internally prepared mid-year reserve report. With a portion of the net proceeds of the offering of our Series B Convertible Preferred Stock in December 2005, we fully repaid all outstanding indebtedness on our revolver in the amount of $47.5 million leaving a zero balance outstanding as of December 31, 2005. Interest on revolving borrowings under the Amended and Restated Credit Agreement accrues at a rate calculated, at our option, at either the bank base rate plus 0.00% to 0.50%, or LIBOR plus 1.25% to 2.00%, depending on borrowing base utilization. BNP Paribas (BNP) is the lead lender and administrative agent under the amended credit facility with Comerica Bank and Harris Nesbit Financing, Inc. as co-lenders.

The terms of the Amended and Restated Credit Agreement require us to maintain certain covenants. The covenants include**:**

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio which is not less than 3.0/1.0 for the trailing four quarters, and
- Tangible Net Worth of not less than $53,392,838, plus 50% of cumulative net income after September 30, 2004, plus 100% of the net proceeds of any subsequent equity issuance.

As of June 30, 2006, we were in compliance with all of the financial covenants of the Amended and Restated Credit Agreement.

The Second Lien Term Loan Agreement provides for a 5-year, non-revolving loan of $30.0 million which was funded on November 17, 2005 and is due in a single maturity on November 17, 2010. Optional prepayments of term loan principal can be made in amounts of not less than $5.0 million during the first year at a 1% premium and without premium after the first year. Interest on term loan borrowings accrues at a rate calculated, at our option, at either base rate plus 3.50%, or LIBOR plus 4.50%, and is payable quarterly. BNP is the lead lender and administrative agent under the Second Lien Term Loan Agreement.

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The terms of the Second Lien Term Loan Agreement require us to maintain certain covenants. Capitalized terms are defined in the loan agreement. The covenants include:

- Total Debt to EBITDAX Ratio which is not greater than 4.0/1.0 for the most recent period of four fiscal quarters for which financial statements are available and
- Asset Coverage Ratio to be not less than 1.5/1.0.

As of June 30, 2006, we were in compliance with all of the financial covenants of the Second Lien Term Loan Agreement.

Cotton Valley Trend

Our relatively low risk development drilling program in the Cotton Valley trend is primarily centered in and around Rusk, Panola, Angelina and Nacogdoches Counties, Texas, and DeSoto and Caddo Parishes, Louisiana. In addition, we have recently expanded our acreage position in the trend to include Harrison, Smith and Upshur Counties of Texas. We have steadily increased our acreage position in these areas over the last two years to approximately 142,000 gross acres (94,000 net acres) as of July 31, 2006. As of July 31, 2006, we have drilled and/or logged a cumulative total of 128 Cotton Valley wells with a 100% success rate, of which drilling operations were conducted on 30 gross wells during the second quarter of 2006. Our net production volumes from our Cotton Valley trend wells aggregated approximately 32,800 Mcfe of gas per day in the second quarter of 2006, or approximately 75% of our total oil and gas production in the period.

In June 2006, we assigned 50% of our interest solely in the deep rights in our Cotton prospect in East Texas, defined as rights below the top of the Knowles Lime formation at 12,901 below the surface, while reserving all of our rights to and above the Upper, Middle and Lower Travis Peak section in approximately 20,500 net acres for approximately $1.6 million. We had received one-half of the sales price as of June 30, 2006 and one-half has been recorded as a receivable in the consolidated financial statements. Pursuant to the agreement, within 18 months of the assignment, the assignee will either pay all of our share of drilling costs to a depth of 16,500 feet in a well (the carried well) drilled on the acreage or pay us a non participation fee of $4.0 million should no well be drilled. The transaction was accounted for as a recovery of cost.

South Louisiana Operations

Burrwood/West Delta 83 Fields In June 2006, our Norton II prospect came on line and as of July 31, 2006 was producing approximately 1,700 Mcf/day and 150 Bbl/day. In late August 2005, our Burrwood/West Delta 83 field was shut-in due to Hurricane Katrina and, except for the partial restoration of oil production in mid September, remained shut-in for the remainder of the third quarter of 2005. Production was gradually restored beginning in the fourth quarter of 2005 through the second quarter of 2006. As of June 30, 2006, we had returned to production all of our total pre-hurricane volumes in South Louisiana, including the Burrwood/West Delta 83 field and the Second Bayou field, which was impacted to a lesser extent by Hurricane Rita in September 2005. Damage to our facilities from both hurricanes was substantially covered by insurance.

St. Gabriel Field In the first quarter of 2006, we commenced an exploratory test well on our Bordeaux Prospect. In March 2006, we announced that an open hole log on the test well, the Gueymard No. 1, had encountered approximately 60 feet of net pay. The well is currently being completed and was preliminarily tested at a gross production rate of approximately 4,000 Mcf of gas per day and 200 barrels of oil per day with 5,000 pounds of flowing tubing pressure. We anticipate first production in the third quarter of 2006.

Accounting Pronouncements

See Note B to our Consolidated Financial Statements for a discussion of recently issued accounting pronouncements.

Other Developments

Texas House Bill 3 (HB3), which was signed into law in May, 2006, provides a comprehensive change in the method of business taxation in Texas. HB3 eliminates the taxable capital and earned surplus components of the existing Texas franchise tax and replaces these components with a taxable margin tax. This change is effective for tax reports filed on or after January 1, 2008 (which are based upon 2007 business activity) and results in no impact on our current Texas income tax.

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We are required to include, in income, the impact of HB3 on our deferred state income taxes during the period which includes the date of enactment. Based upon the available information regarding the proposed implementation of this new tax, we have determined that no change in the amount of net deferred state income taxes is needed since the impact is not significant to the results of operations.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on consolidated financial statements which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts or assets, liabilities, revenues and expenses. We believe that certain accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements. Our 2005 Annual Report on Form 10-K, as amended, includes a discussion of our critical accounting policies. In addition, following the adoption of SFAS 123R, we consider our policies related to share-based compensation to be a critical accounting policy.

Share-Based Compensation Plans. In January 2006, we adopted SFAS 123R which amends SFAS 123 and supercedes APB 25. SFAS 123R requires new, modified and unvested share-based payment transactions with employees to be measured at fair value and recognized as compensation expense over the vesting period. The fair value of each option award is estimated using a Black-Scholes option valuation model that requires us to develop estimates for assumptions used in the model. The Black-Scholes valuation model uses the following assumptions: expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore the dividend yield is zero.

Disclosure Regarding Forward Looking Statement

Certain statements in this Quarterly Report on Form 10-Q regarding future expectations and plans for future activities may be regarded as forward looking statements within the meaning of Private Securities Litigation Reform Act of 1995. They are subject to various risks, such as financial market conditions, operating hazards, drilling risks and the inherent uncertainties in interpreting engineering data relating to underground accumulations of oil and gas, as well as other risks discussed in detail in our Annual Report on Form 10-K, and such material changes to these factors, if any, which are discussed in Part II, Item 1A of this Form 10-Q. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to be correct.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Domestic crude oil and gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis.

We enter into futures contracts or other hedging agreements from time to time to manage the commodity price risk for a portion of our production. We consider these agreements to be hedging activities and, as such, monthly settlements on the contracts that qualify for hedge accounting are reflected in our crude oil and natural gas sales. Our strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our production. As of June 30, 2006, the commodity hedges we utilized were in the form of: (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. See Note H to the Consolidated Financial Statements for additional information.

The fair value of the crude oil and natural gas hedging contracts in place at June 30, 2006 resulted in a liability of $9.9 million. Based on oil and gas pricing in effect at June 30, 2006, a hypothetical 10% increase in oil and gas prices would have increased the derivative liability to $16.1 million while a hypothetical 10% decrease in oil and gas prices would have decreased the derivative liability to an asset of $4.8 million.

Interest Rate Risk

We have variable-rate debt obligations that expose us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. At June 30, 2006 we had the following interest rate swaps in place with BNP (in millions).

Effective Date	Maturity Date	LIBOR Swap Rate	Notional Amount
02/27/06	02/26/07	4.08%	$ 23.0
02/27/06	02/26/07	4.85%	17.0
02/26/07	02/26/09	4.86%	40.0

The fair value of the interest rate swap contracts in place at June 30, 2006 resulted in an asset of $0.8 million. Based on interest rates at June 30, 2006, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the asset.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is recorded, processed, summarized and reported to our management including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

We conducted a review and evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of June 30, 2006. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of June 30, 2006, the end of the fiscal quarter covered in this report, concluded that our disclosure controls and procedures were effective.

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Changes in Internal Control over Financial Reporting

The following changes in our internal control over financial reporting during our most recent fiscal quarter have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

As previously reported in our quarterly report on Form 10-Q for the quarter ended March 31, 2006, a material weakness was identified in our internal control over financial reporting with respect to recording the fair value of all outstanding derivatives. The Public Company Accounting Oversight Board s Auditing Standard No. 2 defines a material weakness as a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

In order to remediate the material weakness, we implemented changes in our internal control over financial reporting during the quarter ended June 30, 2006. Specifically, we now automatically receive a mark to market valuation from our existing counterparties for all outstanding derivatives. For any new contracts entered into with a new counterparty, we will concurrently request this automatic distribution. We also added another layer of review for the fair value calculation prior to review by the Chief Financial Officer.

Our management believes that these additional policies and procedures have enhanced our internal control over financial reporting relating to the determination and review of fair value calculations on outstanding derivatives. Our management also believes that, as a result of these measures described above, the material weakness was remediated and that our internal control over financial reporting is effective as of June 30, 2006, the end of the fiscal quarter covered in this report.

PART II. OTHER INFORMATION

Item 1A Risk Factors

There are no material changes from risk factors previously disclosed in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005 and in the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2006.

Item 4 Submission of Matters to a Vote of Security Holders

The Annual Meeting of Stockholders of the Company was held on May 18, 2006. Set forth below is a brief description of each matter acted upon at the meeting and the number of votes cast for, against or withheld, and abstaining or not voting as to each matter:

		For	Against	Abstained or Withheld
(i)	Election of Class II Directors:			
	Henry Goodrich	22,354,182		1,424,026
	Patrick E. Malloy, III	22,195,522		1,582,686
	Michael J. Perdue	23,725,587		52,621
	Steven A. Webster	21,041,260		2,736,948
(ii)	Approval of First Amendment to the Goodrich Petroleum Corporation 1995 Stock Option Plan.	16,997,730	465,438	6,315,040
(iii)	Approval of Goodrich Petroleum Corporation 2006 Long-Term Incentive Compensation Plan.	16,948,301	513,462	6,316,445
(iv)	Ratification of the appointment of KPMG LLP as the Company s independent registered public accounting firm for 2006.	23,641,679	112,574	23,955

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Item 6 Exhibits

(b) Exhibits

*10.1	Second Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas, dated as of June 21, 2006.
*10.2	Second Amendment to Second Lien Term Loan Agreement among Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of June 21, 2006.
*31.1	Certification of Chief Executive Officer 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 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 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 pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith
** Furnished herewith

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SIGNATURES

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

	GOODRICH PETROLEUM CORPORATION (Registrant)
Date: August 9, 2006	By: /s/ Walter G. Goodrich Walter G. Goodrich Vice Chairman & Chief Executive Officer
Date: August 9, 2006	By: /s/ David R. Looney David R. Looney Executive Vice President & Chief Financial Officer