GOODRICH PETROLEUM CORP
Form 8-K
August 07, 2007

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K
CURRENT REPORT
Pursuant to Section 13 or 15(d)
Of the Securities Exchange Act of 1934
Date of report (Date of earliest event reported): August 7, 2007
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)

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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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ITEM 8.01. OTHER EVENTS.

On March 20, 2007, Goodrich Petroleum Company, L.L.C. (the Company) and Malloy Energy Company, L.L.C., a New York limited liability company collectively with the Company, (the Sellers) closed the sale of substantially all the Sellers assets located in South Louisiana to a private company (the Buyer) pursuant to the Purchase and Sale Agreement dated January 12, 2007 between the Sellers and Buyer. The entry into the Purchase and Sale Agreement was previously disclosed in the Company s Current Report on Form 8-K dated January 19, 2007 (the January 19, 2007 Current Report).

The sale resulted in total proceeds of $74 million, net to the Company, after normal closing adjustments. A detailed description of the assets sold to the Buyer can be found in the Purchase and Sale Agreement, which was filed as Exhibit 10.1 to the Company s January 19, 2007 Current Report, and this description is qualified in its entirety by reference to such exhibit.

The Company issued a press release on March 21, 2007, to announce the closing of the previously announced sale of substantially all of the Company s South Louisiana assets.

The Company reported operations with respect to these properties as discontinued operations in the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007.

This Current Report on Form 8-K was prepared to provide revised financial information that presents these sold properties and other properties held for sale as discontinued operations for all periods presented in the Company s Annual Report on Form 10-K for the year ended December 31, 2006, filed on March 14, 2007 (2006 Form 10-K). It should be noted that the Company s net income (loss) was not impacted by the reclassification of the company s operations with respect to these properties to discontinued operations.

Please note, the Company has not otherwise updated the financial information or business discussion for activities or events occurring after the date this information was presented in the Company s 2006 Form 10-K. You should read the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2007 and Current Reports on Form 8-K and any amendments thereto, for updated information.

This filing includes updated information for the following items included in our 2006 Form 10-K:

ITEM 6. SELECTED FINANCIAL DATA

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Item 6. ***Selected Financial Data***

The following table sets forth our selected financial data and other operating information. The selected consolidated financial data in the table are derived from our consolidated financial statements. The financial statements reflect the sale, on March 20, 2007, of our South Louisiana properties as discontinued operations for each period presented. Discontinued operations in the years 2002, 2003 and 2004 also include the sale in October, 2004 of our West Texas properties. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included herein.

Statement of Operations Data:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share amounts)				
Revenues:					
Oil and gas revenues	$ 73,933	$ 34,986	$ 3,759	$ 1,609	1,989
Other	838	325	151	477	131
	74,771	35,311	3,910	2,086	2,120
Operating Expenses					
Lease operating expense	13,182	3,821	347	507	2,690
Production taxes	2,851	1,809	164	90	122
Transportation	3,791	558			
Depreciation, depletion and amortization	37,225	12,214	1,486	900	2,663
Exploration	5,888	5,697	955	1,591	562
Impairment of oil and gas properties	9,886	340		335	342
General and administrative	17,223	8,622	5,821	5,314	4,468
(Gain) loss on sale of assets	(23)	(235)	(50)	66	(2,941)
	90,023	32,826	8,723	8,803	7,906
Operating income (loss)	(15,252)	2,485	(4,813)	(6,717)	(5,786)
Other income (expense):					
Interest expense	(7,845)	(2,359)	(1,110)	(1,051)	(985)
Gain (loss) on derivatives not qualifying for hedge accounting	38,128	(37,680)	2,317		
Loss on early extinguishment of debt	(612)				
	29,671	(40,039)	1,207	(1,051)	(985)
Income (loss) from continuing operations before income taxes	14,419	(37,554)	(3,606)	(7,768)	(6,771)
Income tax (expense) benefit	(5,120)	13,144	8,594	2,712	2,366
Income (loss) from continuing operations	9,299	(24,410)	4,988	(5,056)	(4,405)
Discontinued operations including gain on sale of assets, net of income taxes	(7,660)	6,960	13,539	8,978	3,454
	1,639	(17,450)	18,527	3,922	(951)

Income (loss) before cumulative effect of change in accounting principle					
Cumulative effect of change in accounting principle net of income taxes				(205)	
Net income (loss)	1,639	(17,450)	18,527	3,717	(951)
Preferred stock dividends	6,016	755	633	633	640
Preferred stock redemption premium	1,545				
Net income (loss) applicable to common stock	$ (5,922)	$ (18,205)	$ 17,894	$ 3,084	$ (1,591)
Income (loss) per common share from continuing operations:					
Basic	$ 0.37	$ (1.05)	$ 0.26	$ (0.28)	$ (0.25)
Diluted	$ 0.37	$ (1.05)	$ 0.25	$ (0.25)	$ (0.25)
Income (loss) per common share from discontinued operations:					
Basic	(0.31)	0.30	0.69	0.50	0.19
Diluted	(0.31)	0.30	0.66	0.44	0.19
Weighted average number of common shares outstanding:					
Basic	24,948	23,333	19,552	18,064	17,908
Diluted	25,412	23,333	20,347	20,482	17,908

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share amounts)				
Balance Sheet Data:					
Total assets	$479,264	$296,526	$127,977	$89,182	$78,567
Total long-term debt	201,500	30,000	27,000	20,000	18,500
Stockholders equity	205,133	181,589	65,307	48,059	44,607

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Forward-Looking Statements

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company s control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to:

planned capital expenditures,

future drilling activity,

our financial condition,

business strategy,

the market prices of oil and gas,

economic and competitive conditions,

legislative and regulatory changes and

financial market conditions.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Although from time to time we make use of futures contracts, swaps, costless collars and fixed-price physical contracts to mitigate risk, fluctuations in oil and gas prices, or a prolonged continuation of low prices may substantially adversely affect the Company s financial position, results of operations and cash flows.

Overview

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. We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 131, *Disclosures about Segments of an Enterprise and Related Information* .

We seek to increase shareholder value by growing our oil and gas reserves, production revenues and operating cash flow. In our opinion, on a long term basis, growth in oil and gas reserves and production, on a cost-effective basis, are the most important indicators of performance success for an independent oil and gas company.

Management strives to increase our oil and gas reserves, production and cash flow through exploration and exploitation activities. We develop an annual capital expenditure budget which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, when establishing our capital expenditure budget.

We place primary emphasis on our internally generated operating cash flow in managing our business. For this purpose, operating cash flow is defined as cash flow from operating activities as reflected in our Statement of Cash Flows. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income.

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Our revenues and operating cash flow are dependent on the successful development of our inventory of capital projects, the volume and timing of our production, as well as commodity prices for oil and gas. Such pricing factors are largely beyond our control, however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Cotton Valley Trend: Expanding Acreage Position and Active Development Drilling Program

Our relatively low risk development drilling program in the Cotton Valley Trend is primarily centered in and around Rusk, Panola, Angelina, Nacogdoches, Cherokee, Harrison, Smith and Upshur Counties, Texas and DeSoto, Caddo and Bienville Parishes, Louisiana. We continue to build our acreage position in the Cotton Valley Trend and now hold approximately 180,000 gross acres as of February 15, 2007. As of year end, we had drilled and/or logged a cumulative total of 156 Cotton Valley wells with a success rate slightly in excess of 99%. Our net production volumes from our Cotton Valley Trend wells aggregated approximately 29,964 Mcfe per day in 2006, or approximately 69% of our total oil and gas production in the period.

Acquisition of Remaining Interests in Dirgin-Beckville Area of Cotton Valley Trend

In early December 2006, we acquired a 14.5% working interest in 22 wells and approximately 3,300 gross (500 net) acres within the Dirgin-Beckville field in the Cotton Valley Trend from a private company for $6.1 million. With the additional interest we now own an approximate 99% working interest in 52 wells and 12,600 gross acres in this field.

Farmout on 21,200 acres in Northwest Louisiana

In November 2006, we announced a definitive farmout agreement covering 21,200 gross acres in 33 sections (16,000 net acres), in the Alabama Bend field of Bienville Parish, Louisiana. The Company has farmed in the right to explore for natural gas and oil at no upfront cost. The Company will own a 100% working interest in the initial well drilled in each of the 33 sections and the Farmor shall have the right to participate up to 50% for future wells drilled. To maintain the rights of the entire acreage block, we must commence drilling operations on one well every 90 days from completion date of the previous well.

Acquisition of Acreage in Angelina River Play in Nacogdoches and Angelina Counties, Texas

On February 7, 2007, we announced the acquisition of drilling and development rights in approximately 16,800 gross acres (8,380 net acres) in the Angelina River play, on trend with our existing acreage in Nacogdoches and Angelina Counties, Texas. We acquired a 60% working interest in the acreage and will operate the joint venture. The acquisition was completed in two separate transactions. In the initial transaction, we acquired a 40% interest for $2.0 million from a private company. We also agreed to carry the private company for a 20% interest in the drilling of five wells. In the second transaction, we purchased the remaining 20% interest in the acreage in a like-kind exchange for our 30% interest in the Mary Blevins field in Smith County, Texas.

South Louisiana Operations: 2007 Sale of Assets

On January 12, 2007, the Company and Malloy Energy Company, LLC (Malloy Energy) entered into a Purchase and Sale Agreement with a private company for the sale of substantially all of the Company s oil and gas properties in South Louisiana. The total sales price for the Company s interest in the oil and gas properties was approximately $100 million, effective July 1, 2006. The total sales price for Malloy Energy s interests in these properties was approximately $30 million with the same effective date. See Note 11 Related Party Transactions to our consolidated financial statements for additional information regarding Malloy Energy. Both the Company and Malloy Energy s total consideration was reduced by an amount equal to its proportionate share of the greater of $20 million or normal closing adjustments. The adjusted sales price for the Company s interest was $77 million. The effective date of the transaction was July 1, 2006 and the closing date of the sale was late March, 2007. Had we completed this transaction at the end of 2006, our proved reserves would have been reduced by approximately 31,700 MMcfe. Average daily production for these properties for the fiscal year-ending December 31, 2006, was approximately 12,904 Mcfe or about 30% of the Company s total production for 2006. This sale will allow us to focus the majority of our efforts on the development of our Cotton Valley Trend acreage, as well as reduce operating costs per unit of production going forward.

Overview of 2006 Results

2006 Financial and operating highlights include:

We increased our oil and gas production volumes on continuing operations 178 percent over 2005. Production averaged 30.5 MMcfe/d compared to 11.0 MMcfe/d in 2005.

Our 2006 oil and gas revenues for continuing operations totaled $73.9 million compared to $35.0 million in 2005, a 111 percent increase.

Net cash provided by operating activities increased $19.6 million from 2005, to $65.1 million.

Estimated proved reserves grew 19 percent to approximately 206.2 Bcfe (approximately 187.0 Bcf of natural gas and 3.2

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MMBbls of oil and condensate), with a pre-tax present value of future net cash flows, discounted at 10%, of $214.2 million and an after-tax present value of discounted future net cash flows of $200.3 million.

Capital expenditures totaled $269.4 million in 2006, versus $164.6 million in 2005.

As operator, we successfully drilled, completed and placed in production 101 wells during calendar year 2006.

We issued $175.0 million in 3.25% convertible senior notes due 2026, completely paying off our Second Lien Term Loan and substantially reducing our bank revolver debt.

Summary Operating Information:

	Year Ended December 31,				Year Ended December 31,			
	2006	2005	Variance		2005	2004	Variance	
	(in thousands, except for price data)							
Net Production-Continuing Operations:								
Natural gas (MMcf)	10,500	3,786	6,714	177%	3,786	408	3,378	828%
Oil and gas condensate (MBbls)	106	38	68	179%	38	33	5	15%
Total (Mmcfe)	11,135	4,012	7,123	178%	4,012	608	3,404	560%
Average daily production (Mmcfe/d)	30,507	10,990	19,517	178%	10,990	1,661	9,329	562%
Net Production-Discontinued Operations:								
Natural gas (MMcf)	2,501	2,451	50	2%	2,451	4,410	(1,959)	(44%)
Oil and gas condensate (MBbls)	368	370	(2)	(1%)	370	442	(72)	(16%)
Total (Mmcfe)	4,710	4,674	36	1%	4,674	7,060	(2,386)	(34%)
Average daily production (Mmcfe/d)	12,904	12,805	99	1%	12,805	19,289	(6,484)	(34%)
Revenues- Continuing Operations:								
Natural Gas	$ 67,372	$ 33,015	$ 34,357	104%	$ 33,015	$ 2,573	$ 30,442	1183%
Oil and condensate	6,561	1,971	4,590	233%	1,971	1,186	785	66%
Natural gas, oil and condensate	73,933	34,986	38,947	111%	34,986	3,759	31,227	831%
Operating revenues	74,771	35,311	39,460	112%	35,311	3,910	31,401	803%
Operating expenses	90,023	32,826	57,197	174%	32,826	8,723	24,103	276%
Operating income (loss)	(15,252)	2,485	(17,737)	(714%)	2,485	(4,813)	7,298	(152%)
Net Income (loss) applicable to common stock	$ (5,922)	$(18,205)	$ 12,283	(67%)	$(18,205)	$17,894	$(36,099)	(202%)

Average Realized Sales price Per Unit From Continuing Operations:								
Average realized price (per Mcf)	6.42	8.72	(2.30)	(26%)	8.72	6.31	2.41	38%
Average realized price (per Bbl)	62.03	52.47	9.56	18%	52.47	35.58	16.89	47%
Average realized price (per Mcfe)	$ 6.64	$ 8.72	$ (2.08)	(24%)	$ 8.72	$ 6.18	$ 2.54	41%

Results of Operations

The financial statements include discontinued operations presentation for our assets located in South Louisiana. See Note 12 Acquisitions and Divestures to our consolidated financial statements.

Operating Income

Year ended December 31, 2006 compared to year ended December 31, 2005

Operating revenues from continuing operations increased 112% or $39.5 million to a total of $74.8 million in 2006 compared to 2005. The increase resulted from an 178% increase in production volumes. The drilling, completion and placing into production of 101 operated wells in the Cotton Valley Trend led to natural gas production more than doubling in 2006. The average realized price for natural gas fell in 2006 by 26% to $6.42 per Mcf. The average realized oil price was strong in 2006, increasing 18% to $62.03 per Bbl.

Year ended December 31, 2005 compared to year ended December 31, 2004

Operating revenues from continuing operations increased 803% or $31.4 million in 2005 compared to 2004. This increase resulted from an increase in oil and gas production volumes, due to a substantial increase in Cotton Valley Trend production, as well as higher average oil and gas prices. We placed 45 Cotton Valley Trend wells on production in 2005. Initial production from the Cotton Valley Trend commenced in June 2004 and we ended 2004 with 11 wells on production.

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Operating Expenses per Mcfe From Continuing Operations:

	Year Ended December 31,				Year Ended December 31,			
	2006	**2005**	**Variance**		**2005**	**2004**	**Variance**	
Lease operating expense	$1.18	$0.95	$ 0.23	24%	$0.95	$0.57	$ 0.38	67%
Production taxes	0.26	0.45	(0.19)	(42%)	0.45	0.27	0.18	67%
Transportation	0.34	0.14	0.20	143%	0.14		0.14	
Depreciation, depletion and amortization	3.34	3.04	0.30	10%	3.04	2.44	0.60	25%
Exploration	0.53	1.42	(0.89)	(63%)	1.42	1.57	(0.15)	(10%)
Impairment of oil and gas properties	0.89	0.08	0.81	1013%	0.08		0.08	
General and administrative	1.55	2.15	(0.60)	(28%)	2.15	9.57	(7.42)	(78%)

Operating Expenses

Year ended December 31, 2006 compared to year ended December 31, 2005

Lease operating expense (LOE) was $13.2 million for 2006 compared to $3.8 million for 2005. Given the rapid pace of our development program in the Cotton Valley Trend in 2006, we experienced significant increases in two major components of LOE, salt water disposal costs ($4.1 million) and compressor rental expense ($2.9 million). With the planned installation of our low pressure gathering system in this region, we expect to see a decline in the per unit LOE charges in 2007. Higher workover activity also contributed to a higher cost per Mcfe in 2006. The majority of this activity occurred during the fourth quarter.

Production taxes were $2.9 million for 2006 versus $1.8 million in 2005. The reduction in production taxes per Mcfe resulted from rebates approved by the State of Texas of $1.3 million. These severance tax rebates relate to a number of our wells which have been approved as high cost tight gas sand wells, allowing us to pay a lower severance tax rate for up to 10 years following certification by the State.

Transportation expense was $3.8 million for 2006 compared to $0.6 million for 2005. The significant increase in transportation expense was due to the requirement for longer transportation segments in our Cotton Valley Trend properties. As our volumes from the Cotton Valley Trend expanded over 181% during 2006, our transportation expense increased accordingly.

Depletion, depreciation and amortization expense (DD&A) was $37.2 million for the year ended December 31, 2006, versus $12.2 million for the year ended December 31, 2005, with the increase due to higher production volumes and higher DD&A rates. The higher rates are a result of an increase in capitalized development costs.

Exploration expense for the year ended December 31, 2006, was $5.9 million versus $5.7 million for the year ended December 31, 2005. Leasehold amortization was $4.8 million versus $2.8 million in 2005.

We recorded an impairment expense of $9.9 million in the year ended December 31, 2006, all of it being determined in conjunction with the receipt of the independent engineer s final report on reserves as of that date. Of the total expense, $8.4 million related to two fields in East Texas which were not a part of the Company s primary Cotton Valley Trend acreage position, and the remaining $1.5 million was spread among several minor properties.

General and administrative (G&A) expenses increased to $17.2 million for the year ended December 31, 2006, from $8.6 million for the year ended December 31, 2005. Stock-based compensation, which consists of the amortization of restricted stock awards and expense associated with our stock option plan, increased to $6.0 million for the year ended December 31, 2006, compared to $1.4 million in 2005. We adopted SFAS 123R on January 1, 2006. 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 requisite service period. See Note 2 Stock-Based Compensation to our consolidated financial statements for additional information.

Year ended December 31, 2005 compared to year ended December 31, 2004

Lease operating expense was $3.8 million for the year ended December 31, 2005 versus $0.3 million for the year ended December 31, 2004, with the increase primarily due to an increase in Cotton Valley Trend production volumes.

Production taxes were $1.8 million for the year ended December 31, 2005 compared to $0.2 million for the year ended December 31, 2004, due to an increase in Cotton Valley Trend production volumes and product prices.

DD&A was $12.2 million for the year ended December 31, 2005, versus $1.5 million for the year ended December 31, 2004, with the increase due to higher production volumes and higher DD&A rates. The higher rates are a result of an increase in capitalized development costs.

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Exploration expense for the year ended December 31, 2005 was $5.7 million versus $1.0 million for the year ended December 31, 2004, primarily due to increased dry hole costs from an exploratory well drilled in East Baton Rouge Parish, Louisiana, and higher non-producing leasehold amortization expense associated with the expansion of our Cotton Valley Trend acreage position.

We recorded an impairment expense of $0.3 million in the recorded value of one property for the year ended December 31, 2005, due to sooner than anticipated depletion of reserves.

G&A increased to $8.6 million for the year ended December 31, 2005, from $5.8 million for the year ended December 31, 2004. This increase was primarily due to higher compensation related costs due to an approximate 25% increase in the number of employees in 2005 and professional fees related to the implementation of the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. Stock-based compensation, which consists of the amortization of restricted stock awards, increased to $1.1 million for the year ended December 31, 2005, compared to $0.6 million for the comparable period in 2004 due to the vesting of awards previously granted.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Other income (expense):			
Interest Expense	$ (7,845)	$ (2,359)	$ (1,110)
Gain (loss) on derivatives not qualifying for hedge accounting	38,128	(37,680)	2,317
Loss on early extinguishment of debt	(612)		
Income tax (expense) benefit	(5,120)	13,144	8,594
Income (loss) from discontinued operations, net of tax	(7,660)	6,960	13,539
Average total borrowings	$99,542	$ 30,417	$22,958
Weighted average interest rate	7.5%	7.0%	3.8%

Other Income (Expense)

Year ended December 31, 2006 compared to December 31, 2005

Interest expense was $7.8 million for 2006, compared to $2.4 million for 2005, with the increase primarily attributable to a higher level of average borrowings in 2006.

Gain on derivatives not qualifying for hedge accounting relates to our ineffective gas hedges for the entire year and for our ineffective oil hedges for the fourth quarter, and amounted to $38.1 million for the year ended December 31, 2006, compared to a loss of $37.7 million for the year ended December 31, 2005. The gain in 2006 includes an unrealized gain of $40.2 million in the mark to market value of our ineffective gas and oil hedges and a realized loss of $2.1 million for the effect of settled derivatives on our ineffective gas and oil hedges. Our natural gas hedges were ineffective again in 2006, and certain oil hedges were deemed ineffective in the fourth quarter of 2006 thereby rendering all of our commodity derivatives ineffective. For these ineffective hedges, we are required to reflect the changes in the fair value of the hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. As applied to our hedging program, there must be a high degree of correlation between the actual prices received and the hedge prices in order to justify treatment as cash flow hedges pursuant to SFAS 133. We perform historical correlation analyses of the actual and hedged prices over an extended period of time. In the fourth quarter of 2006, we determined that certain of our oil hedges which had previously been effective, fell short of the effectiveness guidelines to be accounted for as cash flow hedges. To the extent that our hedges are deemed to be ineffective in the future, we will be exposed to volatility in earnings resulting from changes in the fair value of our hedges.

We fully paid off our Second Lien Term loan in early December 2006 with the proceeds of the 3.25% convertible senior notes offering. In the fourth quarter of 2006, we wrote off remaining deferred loan financing costs of $0.6 million which resulted from the initial funding of this loan and a subsequent amendment.

Income tax expense on continuing operations of $5.1 million which was non-cash represents 35.5% of the pre-tax income in 2006. Income tax benefit of $13.1 million in 2005 represents 35% of pre-tax loss in 2005. The net deferred tax asset as of December 31, 2006, is expected to be realized based upon expected utilization of tax net operating loss carryforwards and the projected reversal of temporary differences.

Loss, net of tax on discontinued operations was $7.7 million for the year ended December 31, 2006 compared to income, net of tax on discontinued operations of $7.0 million for the year ended December 31, 2005, representing substantially all of our oil and gas properties sold or held for sale in South Louisiana. See Note 12 Acquisitions and Divestitures to our consolidated financial statements for a further discussion of our discontinued operations.

Year ended December 31, 2005 compared to year ended December 31 2004

Interest expense was $2.4 million for the year ended December 31, 2005, compared to $1.1 million for the year ended December 31, 2004, with the increase primarily attributable to a higher level of average borrowings in 2005 and a higher total interest rate.

Loss on derivatives not qualifying for hedge accounting relates to our ineffective gas hedges and amounted to $37.7 million for the year ended December 31, 2005, compared to a gain of $2.3 million for the year ended December 31, 2004. The loss in 2005 is related to the change in fair value of our ineffective gas hedges. Since our natural gas hedges were deemed ineffective, beginning in the fourth quarter of 2004, 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. In the fourth quarter of 2004, we initially determined that our gas hedges fell short of the effectiveness guidelines to be accounted for as cash flow hedges and, likewise, made the same determination in each of the four quarters of 2005.

Income taxes from continuing operations were benefits of $13.1 million and $8.6 million for the years ended December 31, 2005 and 2004, respectively, representing 35% of the pre-tax losses and the $7.3 million revision of the deferred tax valuation allowance in 2004.

Income net of tax from discontinued operations was $7.0 million for the year ended December 31, 2005 compared to income net of tax from discontinued operations of $13.5 million for the year ended December 31, 2004. Income net of tax from discontinued operations for 2004 consisted of $12.8 million from operations of our oil and gas properties in South Louisiana and $0.7 million from the after-tax gain realized on the sale of our operated interests in the Marholl and Sean Andrew fields, along with our non-operated interests in the Ackerly field, all of which were located in West Texas.

Liquidity and Capital Resources

Our principal requirements for capital are to fund our exploration and development activities and to satisfy our contractual obligations. These obligations include the repayment of debt and any amounts owing during the period relating to our hedging positions. Our uses of capital include the following:

Drilling and completing new natural gas and oil wells;

Constructing and installing new production infrastructure;

Acquiring and maintaining our lease position, specifically in the Cotton Valley Trend;

Plugging and abandoning depleted or uneconomic wells.

Our capital budget for 2007 is $275 million. We continue to evaluate our capital budget throughout the year.

Future commitments

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2006. See Note 4, Long-Term Debt and Note 10, Commitments and Contingencies to our consolidated financial statements for additional information.

Payments Due by Period

	Note	Total	2007	2008	2009	2010	2011	After 2011
				(in thousands)				
Contractual Obligations								
Long term debt (1)	4	$ 201,500	$	$	$	$ 26,500	$ 175,000	$
Operating lease for office space	10	1,992	701	710	491	48	42	
Drilling rig commitments	10	80,247	45,983	24,956	9,308			

Transportation contracts	10	2,159	758	540	540	321		
Total contractual obligations (2)		$ 285,898	$ 47,442	$ 26,206	$ 10,339	$ 26,869	$ 175,042	$

(1) The $175.0 million convertible senior notes have a provision at the end of years 5, 10 and 15, for the investors to demand payment on these dates; the first such date is December 1, 2011.

(2) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $9.6 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3, Asset Retirement Obligation to our consolidated financial statements.

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Capital Resources

We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with cash flows from our operations, borrowings under our revolving bank credit facility and the proceeds from the 2007 sale of South Louisiana properties. In the future, we may also access public markets to issue additional debt and/or equity securities.

At December 31, 2006, we had $123.5 million of excess borrowing capacity under our revolving bank credit facility. Our primary sources of cash during 2006 were from funds generated from operations, bank borrowings and proceeds received from the issuance of $175.0 million of convertible notes in December 2006. Cash was used primarily to fund exploration and development expenditures. During 2006 we made aggregate cash payments of $7.3 million for interest. There were no payments made in 2006 for federal income taxes. The table below summarizes the sources of cash during 2006, 2005 and 2004:

	Year Ended December 31,			Year Ended December 31,		
Cash flow statement information:	2006	2005	Variance	2005	2004	Variance
			(in thousands)			
Net cash:						
Provided by operating activities	$ 65,133	$ 45,562	$ 19,571	$ 45,562	$ 41,028	$ 4,534
Used in investing activities	(258,737)	(163,571)	(95,166)	(163,571)	(45,414)	(118,157)
Provided by financing activities	179,946	134,402	45,544	134,402	6,346	128,056
Increase(decrease) in cash and cash equivalents	$ (13,658)	$ 16,393	$ (30,051)	$ 16,393	$ 1,960	$ 14,433

At December 31, 2006, we had a working capital deficit of $22.2 million and long-term debt of $201.5 million. The working capital deficit was due to the typical timing difference between the expenditure of funds and accruals resulting from drilling and completion activities.

Cash Flows

Year ended December 31, 2006 compared to year ended December 31, 2005

Operating activities. Cash flow from operations is dependent upon our ability to increase production through development, exploration and acquisition activities and the price of oil and natural gas. Our cash flow from operations is also impacted by changes in working capital. Net cash provided by operating activities increased to $65.1 million, up 43% from $45.6 million in 2005. As previously mentioned, the 112% increase in operating revenues due to higher production volumes from our continuing operations drove the increased cash flow in 2006. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in increases of $4.9 million and $13.2 million for the years ended December 31, 2006 and 2005, respectively.

Investing activities. Net cash used in investing activities was $258.7 million for the year ended December 31, 2006, compared to $163.6 million for 2005. Of the $258.7 million, approximately $211.0 million was spent for drilling and completion activities in the Cotton Valley Trend, versus $139.9 million in 2005.

Financing activities. Net cash provided by financing activities was $179.9 million in 2006 versus $134.4 million in 2005. The majority of our net financing cash flows came from the $175.0 million in convertible note proceeds, and the $29.0 million in convertible preferred proceeds received in 2006.

Year ended December 31, 2005 compared to year ended December 31, 2004

Operating activities. Net cash provided by operating activities increased to $45.6 million, up 11% from $41.0 million in 2004. The increases in 2005 were a result of the increases in natural gas and crude oil prices and production levels in 2005 compared to 2004, partially offset by increases in lease operating expenses, exploration expenses and general and administrative expenses. Including the effect of settled derivatives, sales of oil and gas increased $31.2 million in 2005 compared to 2004, with realized crude oil and natural gas prices and production volumes both increasing in 2005 compared to 2004. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in increases to our operating cash flow in the amounts of $13.2 million and $14.1 million, respectively, in the years ended December 31, 2005 and 2004, reflecting increased revenue and expenditure activity associated with our Cotton Valley Trend wells.

Investing activities. Net cash used in investing activities was $163.6 million for the year ended December 31, 2005, compared to $45.4 million for the year ended December 31, 2004. For the year ended December 31, 2005, capital expenditures totaled $164.6

million primarily due to development on our Cotton Valley Trend wells, which accounted for 85% of the capital costs incurred in 2005. For the year ended December 31, 2004, capital expenditures totaled $47.5 million, as we incurred substantial drilling and leasehold acquisition costs in East Texas and Northwest Louisiana and participated in the drilling of two successful exploratory wells and one successful sidetrack well in the Burrwood/West Delta 83 field. Offsetting these capital expenditures were sales of non-core properties in West Texas and another minor property in the total amount of $2.1 million.

Financing activities. Net cash provided by financing activities was $134.4 million for the year ended December 31, 2005, compared to $6.4 million for the year ended December 31, 2004. In May 2005, we completed a public offering of 3,710,000 shares of our common stock resulting in net proceeds of $53.1 million which was used to repay all then outstanding indebtedness to BNP under a senior credit facility. On December 21, 2005, we issued and sold 1,650,000 shares of our Series B Convertible Preferred Stock for net proceeds as well as bank borrowings of approximately $79.8 million through a private placement.

Our senior credit facility and term loan include certain financial covenants with which we were in compliance as of December 31, 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.

3.25% Convertible Senior Notes

In early December 2006, we issued $125.0 million in convertible senior notes. The intial purchasers option was exercised in full and increased the principal amount to $175.0 million. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes will be our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually and paid semi-annually on June 1 and December 1 beginning June 1, 2007. Prior to December 1, 2011, the notes will not be redeemable. On or after December 11, 2011, we may redeem for cash all or a portion of the notes, and the investors may require us to repay the notes on each of December 11, 2011, 2016 and 2021. The notes are convertible into shares of our common stock at a rate equal to the sum of:

a) 15.1653 shares per $1,000 principal amount of notes (equal to a base conversion price of approximately $65.94 per share) plus,

b) an additional amount of shares per $1,000 of principal amount of notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

Share Lending Agreement

With the offering of the 3.25% convertible senior notes we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock. The shares of stock were lent to the affiliate of BSC under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from such common stock offerings and lending transactions under this agreement. We will not receive any of the proceeds from these transactions. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of shares pursuant to the terms of the 3.25% convertible notes offering.

The 3,122,263 shares of common stock outstanding as of December 31, 2006, under the Share Lending Agreement are required to be returned to the Company. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. There is no impact of the shares of common stock lent under the Share Lending Agreement in the earnings per share calculation.

Senior Credit Facility

In 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Senior Credit Facility) and a second lien term loan (the Term Loan) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Senior Credit Facility were $200.0 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are subject to periodic redeterminations of the borrowing base, which is currently established at $150.0 million, and is scheduled to be redetermined in late March 2007, based upon our 2006 year-end reserve report. With a portion of the net proceeds of the offering of 3.25% Convertible Senior Notes in December 2006, we fully repaid and extinguished the $50.0 million Term Loan and repaid $113.5 million of the Revolving borrowings under the Senior Credit Facility. Interest on revolving borrowings under the Senior Credit Facility 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.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms are defined in the credit agreement. The covenants include:

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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

Total Debt no greater than 3.5 times EBITDAX (1) for the trailing four quarters.

(1) EBITDAX is defined as Earnings before interest expense, income tax, DD&A and exploration expense.

As of December 31, 2006, we were in compliance with all of the financial covenants of the credit agreement.

Series B Convertible Preferred Stock

Our Series B Convertible Preferred Stock (the Series B Convertible Preferred Stock) was initially issued on December 21, 2005, in a private placement of 1,650,000 shares for net proceeds of $79.8 million (after offering costs of $2.7 million). Each share of the Series B Convertible Preferred Stock has a liquidation preference of $50 per share, aggregating to $82.5 million, and bears a dividend of 5.375% per annum. Dividends are payable quarterly in arrears beginning March 15, 2006. If we fail to pay dividends on our Series B Convertible Preferred Stock on any six dividend payment dates, whether or not consecutive, the dividend rate per annum will be increased by 1.0% until we have paid all dividends on our Series B Convertible Preferred Stock for all dividend periods up to and including the dividend payment date on which the accumulated and unpaid dividends are paid in full.

Each share is convertible at the option of the holder into our common stock, par value $0.20 per share (the Common Stock) at any time at an initial conversion rate of 1.5946 shares of Common Stock per share, which is equivalent to an initial conversion price of approximately $31.36 per share of Common Stock. Upon conversion of the Series B Convertible Preferred Stock, we may choose to deliver the conversion value to holders in cash, shares of Common Stock, or a combination of cash and shares of Common Stock.

If a fundamental change occurs, holders may require us in specified circumstances to repurchase all or part of the Series B Convertible Preferred Stock. In addition, upon the occurrence of a fundamental change or specified corporate events, we will under certain circumstances increase the conversion rate by a number of additional shares of Common Stock. A fundamental change will be deemed to have occurred if any of the following occurs:

We consolidate or merge with or into any person or convey, transfer, sell or otherwise dispose of or lease all or substantially all of our assets to any person, or any person consolidates with or merges into us or with us, in any such event pursuant to a transaction in which our outstanding voting shares are changed into or exchanged for cash, securities, or other property, or

We are liquidated or dissolved or adopt a plan of liquidation or dissolution.

A fundamental change will not be deemed to have occurred if at least 90% of the consideration in the case of a merger or consolidation under the first clause above consists of common stock traded on a U.S. national securities exchange and the Series B Preferred Stock becomes convertible solely into such common stock.

On or after December 21, 2010, we may, at our option, cause the Series B Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock that are issuable at the then-prevailing conversion rate, pursuant to the Company Conversion Option. We may exercise our conversion right only if, for 20 trading days within any period of 30 consecutive trading days ending on the trading day prior to the announcement of our exercise of the option, the closing price of the Common Stock equals or exceeds 130% of the then-prevailing conversion price of the Series B Convertible Preferred Stock. The Series B Convertible Preferred Stock is non-redeemable by us.

We used the net proceeds of the offering of Series B Convertible Preferred Stock to fully repay all outstanding indebtedness under our senior revolving credit facility. The remaining net proceeds of the offering were added to our working capital to fund 2006 capital expenditures and for other general corporate purposes.

On January 23, 2006, the initial purchasers of 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, which was used to fund our 2006 capital expenditure program.

Summary of Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list in Note 1 Description of Business and Significant Accounting Policies to our consolidated financial statements.

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Proved oil and natural gas reserves

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by us. We cannot predict the types of reserve revisions that will be required in future periods.

Successful efforts accounting

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells, as well as other exploration expenditures such as seismic costs, are expensed and can have a significant effect on operating results. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by engineers. Certain costs related to fields or areas that are not fully developed are charged to expense using the units of production method based on total proved oil and natural gas reserves.

Impairment of properties

We continually monitor our long-lived assets recorded in oil and gas properties in the Consolidated Balance Sheets to ensure that they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. Performing these evaluations requires a significant amount of judgment since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable proved and probable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves, or other changes to contracts, environmental regulations or tax laws. We cannot predict the amount of impairment charges that may be recorded in the future.

Asset retirement obligations

We are required to make estimates of the future costs of the retirement obligations of our producing oil and gas properties. This requirement necessitates us to make estimates of our property abandonment costs that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

Income taxes

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate our tax operating loss and other carryforwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in our financial statements. As of December 31, 2006, and in certain prior years, we have reported a net deferred tax asset on our Consolidated Balance Sheet, after deduction of the related valuation allowance, which has been determined on the basis of management s estimation of the likelihood of realization of the gross deferred tax asset as a deduction against future taxable income.

Derivative Instruments

As discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk, we periodically utilize derivative instruments to manage both our commodity price risk and interest rate risk. We consider the use of these instruments to be hedging activities. Pursuant to derivative accounting rules, we are required to use mark to market accounting to reflect the fair value of such derivative instruments on our Consolidated Balance Sheet. To the extent that we are able to demonstrate that our use of derivative instruments qualifies as hedging activities, the offsetting entry to the changes in fair value of these instruments is accounted for in Other Comprehensive Income (Loss). To the extent that such derivatives are deemed to be ineffective, the offsetting entry to the changes in fair value is reflected in earnings.

At the inception of each hedge, we document that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. A hedge must be determined to be highly effective under accounting rules in order to qualify for hedge accounting treatment. This assessment, which is updated quarterly, includes an evaluation of the most recent historical correlation

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between the derivative and the item hedged. In this analysis, changes in monthly settlement prices on our oil and gas derivatives are compared with the change in physical daily indexed prices that we receive from the field purchasers for our oil and gas production designated for hedging. Should a hedge not be highly effective , it no longer qualifies for hedge accounting treatment and changes in fair value of the hedge are recognized in earnings.

Price volatility within a measured month is the primary factor affecting the analysis of effectiveness of our oil and natural gas swaps. Volatility can reduce the correlation between the hedge settlement price and the price received for physical deliveries. Secondary factors contributing to changes in pricing differentials include changes in the basis differential which is the difference in the locally indexed price received for daily physical deliveries of hedged quantities and the index price used in hedge settlement, and changes in grade and quality factors of the hedged oil and natural gas production which would further impact the price received for physical deliveries.

Not withstanding the determination that certain commodity swaps in 2005 and the fourth quarter of 2006, were not highly effective, management continues to believe that our oil and gas price hedge strategy has been effective in satisfying our financial objective of providing cash flow stability.

Our hedge agreements currently consist 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. The terms of our current hedge agreements are described in Note 8 Hedging Activities to our consolidated financial statements.

Share-Based Compensation Plans

For all new, modified and unvested share-based payment transactions with employees, we measure at fair value and recognize as compensation expense over the requisite 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.

New Accounting Pronouncements

See Note 1 Description of Business and Significant Accounting Policies New Accounting Pronouncements to our consolidated financial statements.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance our liquidity and capital resource positions, or for any other purpose.

Item 7A. *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 December 31, 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 8 Hedging Activities to our consolidated financial statements for additional information.

Our hedging contracts fall within our targeted range of 30% to 70% of our estimated net oil and gas production volumes for the applicable periods of 2006. The fair value of the crude oil and natural gas hedging contracts in place at December 31, 2006, resulted in an asset of $13.4 million. Based on oil and gas pricing in effect at December 31, 2006, a hypothetical 10% increase in oil and gas prices would have decreased the derivative asset to $11.9 million while a hypothetical 10% decrease in oil and gas prices would have increased the derivative asset to $14.9 million.

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Interest Rate Risk

We have a variable-rate debt obligation that exposes 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 December 31, 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
02/27/07	02/26/09	4.86%	40.0

The fair value of the interest rate swap contracts in place at December 31, 2006, resulted in an asset of $0.2 million. Based on interest rates at December 31, 2006, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the asset.

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Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Goodrich Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, stockholders equity and comprehensive income (loss) for each of the years in the three-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for share based payments.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 14, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP
New Orleans, Louisiana

March 14, 2007 except for the effects of discontinued operations, as discussed in Note 12, which is as of August 6, 2007

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(In Thousands, Except Share Amounts)

	December 31, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,184	$ 19,842
Accounts receivable, trade and other, net of allowance	9,665	6,397
Accrued oil and gas revenue	10,689	11,863
Fair value of oil and gas derivatives	13,419	
Fair value of interest rate derivatives	219	107
Prepaid expenses and other	994	463
Total current assets	41,170	38,672
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	575,666	316,286
Furniture, fixtures and equipment	1,463	1,075
	577,129	317,361
Less: Accumulated depletion, depreciation and amortization	(156,509)	(74,229)
Net property and equipment	420,620	243,132
OTHER ASSETS:		
Restricted cash and investments	2,039	2,039
Deferred tax asset	9,705	11,580
Other	5,730	1,103
Total other assets	17,474	14,722
TOTAL ASSETS	$ 479,264	$ 296,526
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 36,263	$ 31,574
Accrued liabilities	26,811	15,973
Fair value of oil and gas derivatives		23,271
Accrued abandonment costs	263	92
Total current liabilities	63,337	70,910
LONG-TERM DEBT	201,500	30,000
Accrued abandonment costs	9,294	7,868
Fair value of oil and gas derivatives		6,159
Total liabilities	274,131	114,937

Commitments and contingencies (See Note 10)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized:		
Series A convertible preferred stock, $1.00 par value, issued and outstanding none and 791,968 shares, respectively		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 28,218,422 and 24,804,737 shares, respectively	5,049	4,961
Additional paid in capital	213,666	187,967
Accumulated deficit	(14,571)	(8,649)
Unamortized restricted stock awards		(2,066)
Accumulated other comprehensive loss	(1,261)	(3,066)
Total stockholders equity	205,133	181,589
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 479,264	$ 296,526

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2006	2005	2004
REVENUES:			
Oil and gas revenues	$ 73,933	$ 34,986	$ 3,759
Other	838	325	151
	74,771	35,311	3,910
OPERATING EXPENSES:			
Lease Operating expense	13,182	3,821	347
Production taxes	2,851	1,809	164
Transportation	3,791	558	
Depreciation, depletion and amortization	37,225	12,214	1,486
Exploration	5,888	5,697	955
Impairment of oil and gas properties	9,886	340	
General and administrative	17,223	8,622	5,821
Gain on sale of assets	(23)	(235)	(50)
	90,023	32,826	8,723
Operating income (loss)	(15,252)	2,485	(4,813)
OTHER INCOME AND (EXPENSE)			
Interest expense	(7,845)	(2,359)	(1,110)
Gain (loss) on derivatives not qualifying for hedge accounting	38,128	(37,680)	2,317
Loss on early extinguishment of debt	(612)		
	29,671	(40,039)	1,207
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	14,419	(37,554)	(3,606)
INCOME TAX (EXPENSE) BENEFIT	(5,120)	13,144	8,594
INCOME (LOSS) FROM CONTINUING OPERATIONS	9,299	(24,410)	4,988
Discontinued operations including gain on sale of assets, net of tax	(7,660)	6,960	13,539
NET INCOME (LOSS)	1,639	(17,450)	18,527
PREFERRED STOCK DIVIDENDS	6,016	755	633
PREFERRED STOCK REDEMPTION PREMIUM	1,545		
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (5,922)	$ (18,205)	$ 17,894

NET INCOME (LOSS) PER COMMON SHARE-BASIC			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 0.37	$ (1.05)	$ 0.26
DISCONTINUED OPERATIONS	$ (0.30)	$ 0.30	$ 0.69
NET INCOME (LOSS)	$ 0.07	$ (0.75)	$ 0.95
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (0.24)	$ (0.78)	$ 0.92
NET INCOME (LOSS) PER COMMON SHARE-DILUTED			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 0.37	$ (1.05)	$ 0.25
DISCONTINUED OPERATIONS	$ (0.31)	$ 0.30	$ 0.66
NET INCOME (LOSS)	$ 0.06	$ (0.75)	$ 0.91
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (0.24)	$ (0.78)	$ 0.88
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING-BASIC	24,948	23,333	19,552
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING-DILUTED	25,412	23,333	20,347

See accompanying notes to consolidated financial statements

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$ 1,639	$ (17,450)	$ 18,527
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	52,642	25,563	11,717
Unrealized (gain) loss on derivatives not qualifying for hedge accounting	(40,185)	26,960	(2,317)
Deferred income taxes	904	(9,396)	(1,303)
Dry hole costs	7,926	2,014	
Amortization of leasehold costs	5,488	3,344	1,035
Impairment of oil and gas properties	24,790	340	
Stock based compensation (non-cash)	5,962	1,383	1,031
Loss on early extinguishment of debt	612		
Gain on sale of assets	(23)	(235)	(814)
Other non-cash items	476	(156)	(967)
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	(3,268)	786	(3,683)
Accrued oil and gas revenue	1,174	(8,741)	(293)
Prepaid expenses and other	(531)	169	(280)
Accounts payable	4,689	8,222	16,644
Accrued liabilities	2,838	12,759	1,731
Net cash provided by operating activities	65,133	45,562	41,028
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(261,435)	(164,551)	(47,501)
Proceeds from sale of assets	2,698	980	2,087
Net cash used in investing activities	(258,737)	(163,571)	(45,414)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of bank borrowings	(184,500)	(118,500)	(1,000)
Proceeds from bank borrowings	181,000	121,500	8,000
Proceeds from convertible note offering	175,000		
Net proceeds from common stock offering		53,112	
Net proceeds from preferred stock offering	28,973	79,775	
Redemption of preferred stock	(9,319)		
Exercise of stock options and warrants	406	477	340
Production payments		(297)	(361)
Deferred financing costs	(5,598)	(971)	
Preferred stock dividends	(6,016)	(634)	(633)
Other		(60)	

Net cash provided by financing activities	179,946	134,402	6,346
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(13,658)	16,393	1,960
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	19,842	3,449	1,489
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 6,184	$ 19,842	$ 3,449
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
CASH PAID DURING THE YEAR FOR INTEREST	$ 7,284	$ 1,862	$ 865
CASH PAID DURING THE YEAR FOR INCOME TAXES	$	$ 110	$ 30

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In Thousands)

	2006		2005		2004	
	Shares	Amount	Shares	Amount	Shares	Amount
Series A Preferred Stock						
Balance, beginning of year	792	$ 792	792	$ 792	792	$ 792
Offering of preferred stock	(792)	(792)				
Balance, end of year		$	792	$ 792	792	$ 792
Series B Preferred Stock						
Balance, beginning of year	1,650	$ 1,650		$		$
Offering of preferred stock			1,650	1,650		
Issuance of preferred stock	600	600				
Balance, end of year	2,250	$ 2,250	1,650	$ 1,650		$
Common stock						
Balance, beginning of year	24,805	$ 4,961	20,587	$ 4,117	18,130	$ 3,626
Offering of common stock			3,710	742		
Redemption of Series A preferred stock	6	1				
Issuance of and amortization of restricted stock	182	36	123	25	52	10
Exercise of stock options and warrants	66	44	371	74	2,376	475
Director stock grants	37	7	14	3	29	6
Shares pursuant to share lending agreement	3,122					
Balance, end of year	28,218	$ 5,049	24,805	$ 4,961	20,587	$ 4,117
Paid in Capital						
Balance, beginning of year		$ 187,967		$ 55,409		$ 53,359
Offering of common stock				52,370		
Offering of preferred stock		28,373		78,125		
Redemption of Series A preferred stock		(6,983)				
Issuance of and amortization of restricted stock		2,205		1,423		1,951
Reclassification from unamortized restricted stock upon adoption of FAS 123R		(2,066)				
Stock based compensation		2,487				
Exercise of stock options and warrants		295		403		(135)
Director stock grants		1,388		237		234
Balance, end of year		$ 213,666		$ 187,967		$ 55,409
Retained Earnings(Deficit)						
Balance, beginning of year		(8,649)		9,556		(8,338)
Net income(loss)		1,639		(17,450)		18,527

Redemption of Series A preferred stock	(1,545)		
Preferred stock dividend	(6,016)	(755)	(633)
Balance, end of year	$ (14,571)	$ (8,649)	$ 9,556
Unamortized Restricted Stock Awards			
Balance, beginning of year	$ (2,066)	(1,762)	(382)
Issuance of and amortization of restricted stock		(304)	(1,380)
Reclassification to APIC upon adoption of FAS 123R	2,066		
Balance, end of year	$	$ (2,066)	$ (1,762)
Accumulated Other Comprehensive Loss			
Balance, beginning of year	$ (3,066)	$ (2,805)	$ (998)
Other comprehensive loss	1,805	(261)	(1,807)
Balance, end of year	$ (1,261)	$ (3,066)	$ (2,805)
Total Stockholder s Equity at December 31,	$ 205,133	$ 181,589	$ 65,307

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In Thousands)

	Year Ended December 31,		
	2006	2005	2004
Net income (loss)	$ 1,639	$ (17,450)	$ 18,527
Other comprehensive income (loss):			
Change in fair value of derivatives (1)	(1,025)	(6,233)	(5,909)
Reclassification adjustment (2)	2,830	5,972	4,102
	1,805	(261)	(1,807)
Other comprehensive income (loss)	$ 3,444	$ (17,711)	$ 16,720
Comprehensive income (loss)			
(1) Net of income tax benefit of:	$ 552	$ 3,356	$ 3,180
(2) Net of income tax expense of:	$ 1,524	$ 3,216	$ 2,209

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Significant Accounting Policies

We are in the primary business of exploration and production of crude oil and natural gas. We and our subsidiaries have interests in such operations in three states, primarily in Texas and Louisiana.

Principles of Consolidation The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiaries. 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.

Use of Estimates Our Management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

Cash and Cash Equivalents Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase. Restricted cash represents amounts held in escrow for plugging and abandonment obligations which were incurred with the acquisition of our Burrwood and West Delta 83 fields in 2000.

Revenue Recognition Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized on the entitlements method. We record an asset or liability for natural gas balancing when we have purchased or sold more than our working interest share of natural gas production, respectively. At December 31, 2006 and 2005, the net assets for gas balancing were $1.5 million and $0.7 million, respectively. Differences between actual production and net working interest volumes are routinely adjusted. These differences are not significant.

Property and Equipment We use the successful efforts method of accounting for exploration and development expenditures. Leasehold acquisition costs are capitalized. When proved reserves are found on an undeveloped property, leasehold cost is reclassified to proved properties. Significant undeveloped leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Cost of all other undeveloped leases is amortized over the estimated average holding period of the leases.

Costs of exploratory drilling are initially capitalized, but if proved reserves are not found the costs are subsequently expensed. All other exploratory costs are charged to expense as incurred. Development costs are capitalized, including the cost of unsuccessful development wells.

We recognize an impairment when the net of future cash inflows expected to be generated by an identifiable long-lived asset and cash outflows expected to be required to obtain those cash inflows is less than the carrying value of the asset. We perform this comparison for our oil and gas properties on a field-by-field basis using our estimates of future commodity prices and proved and probable reserves. The amount of such loss is measured based on the difference between the discounted value of such net future cash flows and the carrying value of the asset. For the years ended December 31, 2006 and 2005, we recorded impairments on continuing operations of $9.9 million and $0.3 million, respectively, as a result of certain non-core fields depleting earlier than anticipated. There were no impairments in 2004.

Depreciation and depletion of producing oil and gas properties are provided under the unit-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs. As described in Note 3, we follow the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). Our asset retirement obligations are amortized based upon units of production of proved reserves attributable to the properties to which the obligations relate. Some of these obligations relate to an individual producing well or group of producing wells and are amortized based on proved developed reserves attributable to that well or group of wells. Other asset retirement obligations may relate to an entire field or area that is not fully developed. Because these obligations relate to assets installed to service future development, they are amortized based on all proved reserves attributable to the field or area.

Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in income. All other dispositions, retirements, or abandonments are reflected in accumulated depreciation, depletion, and amortization.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Furniture, fixtures and equipment consists of office furniture, computer hardware and software and leasehold improvements. Depreciation of these assets is computed using the straight-line method over their estimated useful lives, which vary from one to five years.

Income Taxes We follow the provisions of SFAS No. 109, *Accounting for Income Taxes* , (SFAS 109) which requires income taxes be accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Earnings Per Share Basic income per common share is computed by dividing net income available for common stockholders, for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income available for common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive common shares.

Derivative Instruments and Hedging Activities We utilize derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. Upon entering into a derivative contract, we may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, mark the contract to market through earnings. We document the relationship between the derivative instrument designated as a hedge and the hedged items, as well as our objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. We assess at inception, and on an ongoing basis, whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the Statement of Operations, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings.

Ineffective portions of a cash flow hedging derivative s change in fair value are recognized currently in earnings as other income (expense). If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in other comprehensive income is recognized over the period anticipated in the original hedge transaction.

Asset Retirement Obligations We follow SFAS 143 (see Note 3) which applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. SFAS 143 requires that we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset.

Commitments and Contingencies Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, which are probable of realization, are separately recorded, and are not offset against the related environmental liability.

Concentration of Credit Risk Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant.

Revenues from two purchasers accounted for 35% and 15% of oil and gas revenues for the year ended December 31, 2006. For the year ended December 31, 2005, revenue from three purchasers accounted for 34%, 18% and 13% of oil and gas revenues. For the year ended December 31, 2004, revenues from two purchasers accounted for 45% and 15%, of oil and gas.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Share-Based Compensation Plans. In December 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R), replacing SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and superseding Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25). In January 2006, we adopted SFAS 123R which replaces SFAS 123 and supersedes 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 requisite service 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. See Note 2.

New Accounting Pronouncements In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115,* which allows measurement at fair value of eligible financial assets and liabilities that are not otherwise measured at fair value. If the fair value option for an eligible item is elected, unrealized gains and losses for that item shall be reported in current earnings at each subsequent reporting date. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. Early adoption is permitted. We are currently assessing the impact of SFAS 159 on our financial statements.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108 (SAB 108), which became effective for fiscal years ending after November 15, 2006. SAB 108 provides guidance on the consideration of the effects of prior period misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 requires an entity to evaluate the impact of correcting all misstatements, including both the carryover and reversing effects of prior year misstatements, on current year financial statements. If a misstatement is material to the current year financial statements, the prior year financial statements should also be corrected, even though such revision was, and continues to be, immaterial to the prior year financial statements. Correcting prior year financial statements for immaterial errors would not require previously filed reports to be amended. Such correction should be made in the current period filings. The adoption of this standard at December 31, 2006 had no impact on the company s financial statements.

In December 2006, FASB issued a FASB Staff Position (FSP) EITF 00-19-2 *Accounting for Registration Payment Arrangements* (FSP 00-19-2). This FSP addresses an issuer s accounting for registration payment arrangements. This FSP specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with FASB Statement No. 5 *Accounting for Contingencies.* The guidance in this FSP amends FASB Statements No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity,* as well as FASB Interpretation No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* to include scope exceptions for registration payment arrangements. This FSP is effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to the date of issuance of this FSP. For registration payment arrangements and financial instruments subject to those arrangements that were entered into prior to the issuance of this FSP, this is effective for financial statements issued for fiscal years beginning after December 15, 2006, and interim periods within those fiscal years. We are currently evaluating the impact that the implementation of FSP EITF 00-19-2 may have in our consolidated results of operations and financial position.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS 157), which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, this Statement does not require any new fair value measurements. SFAS 157 is effective for fiscal years beginning after December 15, 2007. We plan to adopt SFAS 157 beginning in the first quarter of fiscal 2008. We are currently evaluating the impact, if any, the adoption of SFAS 157 will have on our consolidated financial position, results of operations or cash flows.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In July 2006, the FASB issued Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48). FIN 48, which clarifies SFAS 109, establishes the criterion that an individual tax position has to meet for some or all of the benefits of that position to be recognized in our consolidated financial statements. On initial application, FIN 48 will be applied to all tax positions for which the statute of limitations remains open. Only tax positions that meet the more-likely-than-not recognition threshold at the adoption date will be recognized or continue to be recognized. The cumulative effect of applying FIN 48 will be reported as an adjustment to retained earnings at the beginning of the period in which it is adopted. FIN 48 is effective for fiscal years beginning after December 15, 2006, and we plan to adopt FIN 48 on January 1, 2007. We do not expect that the adoption of FIN 48 will have a significant effect on our consolidated financial statements or our ability to comply with our current debt covenants.

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.

We do not believe that any other recently issued, but not yet effective accounting pronouncements, if adopted, would have a material effect on our accompanying financial statements.

NOTE 2 Stock-Based Compensation

Share-Based Employee Compensation Plans

Stock Option and Incentive Programs

We have historically had two plans, which provide for stock option and other incentive awards for our key employees, consultants and directors: (a) the Goodrich Petroleum Corporation 1995 Stock Option Plan (the 1995 Plan), which allowed grants of stock options, restricted stock awards, stock appreciation rights, long-term incentive awards and phantom stock awards, or any combination thereof, to key employees and consultants, and (b) the Goodrich Petroleum Corporation 1997 Director Compensation Plan (the Directors Plan), which allowed grants of stock and options to each director who is not and has never been an employee of the Company. The Goodrich Petroleum Corporation 1995 Stock Option Plan expired according to its original terms in late 2005; however, our Board of Directors approved the extension of the 1995 Plan through December 31, 2005 and the granting of a total of 525,000 stock options at an exercise price of $23.39 and 101,129 shares of restricted stock to certain of our employees and officers as of December 6, 2005, subject to approval at our 2006 Annual Meeting of Stockholders. As of February 9, 2006, our directors and executive officers reached a level of more than 50% ownership of our total shares of Common Stock outstanding; therefore, stockholder approval of these actions was no longer contingent. For accounting purposes, we began expensing the December 6, 2005 grants based on the grant date value as determined under SFAS 123R, which utilizes the closing price of our Common Stock as of February 9, 2006. At our 2006 Annual Meeting of Stockholders, a proposal to implement a new combined plan to replace both the Goodrich Petroleum Corporation 1995 Stock Option Plan and the Goodrich Petroleum Corporation 1997 Director Compensation Plan was approved.

Prior to the expiration of the 1995 Stock Option Plan, the two Goodrich plans had authorized grants of options to purchase up to a combined total of 2,300,000 shares of authorized but unissued common stock. Stock options under both plans were granted with an exercise price equal to the stock s fair market value at the date of grant, and all employee stock options granted under the 1995 Stock Option Plan generally had ten year terms and three year pro rata vesting. Share options granted under the Director Plan generally became exercisable immediately and expire, if not exercised, ten years thereafter.

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.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

At December 31, 2006, options to purchase 100,000 shares of our common stock were outstanding under the 2006 Plan and options to purchase 923,500 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.

A summary of stock option activity is as follows:

	Number of Options	Weighted Average Exercise Price	Range of Exercise Price	Weighted Average Remaining Contractual Life
Outstanding, January 1, 2004	236,813		$ 0.75 to $5.85	7.7 yrs
Granted 1995 stock option plan	220,000	16.46		
Exercised 1995 stock option plan	(2,750)	2.90		
Exercised 1997 director compensation plan	(43,563)	3.74		
Outstanding, December 31, 2004	410,500		$ 0.75 to $16.46	8.5 yrs
Granted 1997 director compensation plan	150,000	19.78		
Exercised 1995 stock option plan	(25,000)	2.88		
Exercised 1997 director compensation plan	(16,000)	4.92		
Outstanding, December 31, 2005	519,500	13.70	$ 0.75 to $19.78	8.4 yrs
Granted 2006 stock option plan	625,000	24.10		
Exercised 1995 stock option plan	(66,000)	7.23		
Forfeited 1995 stock option plan	(55,000)	22.13		
Outstanding, December 31, 2006	1,023,500	20.01	$ .75 to $27.81	8.2 yrs
Exercisable, December 31, 2004	169,500	3.20		
Exercisable, December 31, 2005	372,100	12.60		
Exercisable, December 31, 2006	492,167	16.36		

Adoption of New Accounting Pronouncement

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,

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. Prior period financial statements have not been restated.

In 2003 we commenced granting a series of restricted share awards with three year vesting periods to eligible employees. During 2006, 2005 and 2004, we contributed $7.1 million, $1.5 million and $2.1 million, respectively, under the plan through the issuance of 215,629, 75,750 and 238,750 shares, respectively, of our common stock. During 2006, 2005 and 2004, $2.1 million, $1.1 million and $0.6 million, respectively, were charged to compensation expense related to the restricted share awards. During 2006, 2005 and 2004, we recorded credits to the contra equity account of $0.4 million, $0.1 million and $0.2 million, respectively, for the value of 18,162, 12,832 and 28,918 shares, respectively, of non-vested restricted share awards that were forfeited by terminated employees. The fair value of restricted stock vested during 2006, 2005, and 2004 were $1.4 million, $0.8 million, and $0.2 million, respectively.

Total stock based compensation for the year ended December 31, 2006, of $5.7 million has been recognized as a component of general and administrative expenses in the accompanying 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 year ended December 31, 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. Our net income and net income per share for the year ended December 31, 2004, would have been less if compensation cost related to stock options had been recorded in the financial statements based on fair values at the grant dates.

Pro forma net income (loss) as if the fair value based method had been applied to all awards for the years ended December 31, 2005 and 2004, is as follows (in thousands, except per share amounts):

	2005	2004
Net income (loss) as reported	$ (17,450)	$ 18,527
Add: Stock based compensation programs recorded as expense, net of tax	743	579
Deduct: Total stock based compensation expense, net of tax	(1,236)	(609)
Pro forma net income (loss)	$ (17,943)	$ 18,497
Net income (loss) applicable to common stock, as reported	$ (18,205)	$ 17,894
Add: Stock based compensation programs recorded as expense, net of tax	743	579
Deduct: Total stock based compensation expense, net of tax	(1,236)	(609)
Pro forma net income (loss) applicable to common stock	$ (18,698)	$ 17,864
Net income (loss) applicable to common stock per share:		
Basic as reported	$ (0.78)	$ 0.92

Basic pro forma	$	(0.80)	$	0.91
Diluted as reported	$	(0.78)	$	0.88
Diluted pro forma	$	(0.80)	$	0.88

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The per share weighted average fair value of stock options granted during the years ended December 31, 2006, 2005 and 2004, were $12.98, $9.69 and $7.96, respectively, on the date of grant.

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:

	December 31, 2006	December 31, 2005	December 31, 2004
Risk free interest rate	4.50-4.97%	4.50-6.00%	6%
Weighted average volatility	54-57%	47-57%	46%
Dividend yield	0%	0%	0%
Expected years until exercise	5-6	5	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.

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

	Year Ended December 31,		
	2006	2005	2004
Restricted stock:			
Pretax compensation expense	$ 2,092	$ 1,143	$ 891
Tax benefit	(732)	(400)	(312)
Restricted stock expense, net of tax	$ 1,360	$ 743	$ 579
Director stock grants:			
Pretax compensation expense	$ 1,383	$ 240	$ 140
Tax benefit	(484)	(84)	(49)
Director stock grants expense, net of tax	$ 899	$ 156	$ 91
Stock options:			
Pretax compensation expense	$ 2,487	$	$
Tax benefit	(870)		

Stock option expense, net of tax	$ 1,617	$	$
Total share based compensation:			
Pretax compensation expense	$ 5,962	$ 1,383	$ 1,031
Tax benefit	(2,086)	(484)	(361)
Total share based compensation expense, net of tax	$ 3,876	$ 899	$ 670

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2006, $6.6 million and $7.0 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 1.9 years for restricted stock and 1.8 years for stock options.

Option activity under our stock option plans as of December 31, 2006, and changes during the 12 months then ended were as follows:

	Shares	Wtd. Avg. Exercise Price	Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	519,500	$ 13.70		
Granted	625,000	24.10		
Exercised	(66,000)	7.24		
Forfeited	(55,000)	22.13		
Outstanding at December 31, 2006	1,023,500	$ 20.01	8.2	$ 16,547,788
Exercisable at December 31, 2006	492,167	$ 16.36	7.5	$ 9,755,141

The aggregate intrinsic value in the preceding table represents the total pre-tax intrinsic value (the difference between our closing stock price on the last trading day of the fourth 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 December 31, 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 year ended December 31, 2006, 2005, and 2004 was $1.7 million, $0.8 million, and $0.4 million respectively.

The following table summarizes information on unvested restricted stock outstanding as of December 31, 2006:

	Number of Shares	Weighted Average Grant-Date Fair Value
Unvested at January 1, 2006	263,890	$ 11.13
Vested	(182,303)	12.03
Granted	215,629	32.72
Forfeited	(18,162)	21.54
Unvested at December 31, 2006	279,054	$ 26.12

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.

In December of 2006, a second officer of the company resigned and the company accelerated the vesting of 6,749 shares of previously unvested restricted stock that had been issued over the period of 2004-2005. The unamortized balance of $0.1 million was immediately recognized as compensation expense.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In December of 2006, the non-employee Directors of the company were granted a total of 26,824 shares of unrestricted stock to compensate them for past services. The charge in the financial statements relative to this grant is based on the fair market value of the shares at the grant date, and resulted in additional compensation expense of $1.1 million.

NOTE 3 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 periods ending December 31, 2006 and 2005 is as follows (in thousands):

	December 31,	
	2006	2005
Beginning balance	$ 7,960	$ 6,811
Liabilities incurred	1,366	1,004
Liabilities settled	(190)	(39)
Accretion expense		
Reflected in depreciation, depletion and amortization	153	70
Reflected in discontinued operations	285	293
Other	(17)	(179)
Ending balance	9,557	7,960
Less: current portion	(263)	(92)
	$ 9,294	$ 7,868

NOTE 4 Long-Term Debt

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

	December 31,	
	2006	2005
Senior Credit Facility (see below for rate detail)	$ 26,500	$
Second-lien Term Loan, bearing interest at a weighted average interest rater of 8.9% at December 31, 2005		30,000
3.25% convertible senior notes due 2026	175,000	
Total debt	201,500	30,000
Less current maturities		
Total long-term debt	$ 201,500	$ 30,000

In December 2006, we sold $175 million of 3.25% convertible senior notes due in December, 2026. With a portion of the proceeds of the note offering we fully repaid the outstanding balance of the second lien term loan. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes will be our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually and paid semi-annually on June 1 and December 1 beginning June 1, 2007.

Prior to December 1, 2011, the notes will not be redeemable. On or after December 11, 2011, we may redeem for cash all or a portion of the notes, and the investors may require us to repay the notes on each of December 11, 2011, 2016 and 2021. The notes are convertible into shares of our common stock at a rate equal to the sum of

a) 15.1653 shares per $1,000 principal amount of notes (equal to a base conversion price of approximately $65.94 per share) plus

b) an additional amount of shares per $1,000 of principal amount of notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On November 17, 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Senior Credit Facility) and a second lien term loan (the Term Loan) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Senior Credit Facility were $200.0 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are subject to periodic redeterminations of the borrowing base which is currently established at $150.0 million, and is currently scheduled to be redetermined in March 2007, based upon our 2006 year-end reserve report. In 2006, we fully repaid $50.0 million on the Term Loan and repaid $134.5 million of the revolving borrowings under the Senior Credit Facility. Interest on revolving borrowings under the Senior Credit Facility 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. At December 31, 2006, we had $123.5 million of excess borrowing capacity under our revolving bank credit facility.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms are defined in the credit agreement. 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

Total Debt no greater than 3.5 times EBITDAX for the trailing four quarters.

EBITDAX is earnings before interest expense, income tax, DD&A and exploration expense.

As of December 31, 2006, we were in compliance with all of the financial covenants of the Amended and Restated Credit Agreement.

NOTE 5 Net Income (Loss) Per Common Share

Net income (loss) was used as the numerator in computing basic and diluted income (loss) per common share for the years ended December 31, 2006, 2005 and 2004. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

	Year Ended December 31,		
	2006	**2005**	**2004**
Basic method	24,948	23,333	19,552
Stock warrants	129		478
Stock options and restricted stock	335		317
Dilutive method	25,412	23,333	20,347

NOTE 6 Income Taxes

Income tax (expense) benefit consisted of the following (in thousands):

	Year Ended December 31,		
	2006	**2005**	**2004**
Current:			
Federal	$	$	$
State			
Deferred:			
Federal	(904)	9,397	1,303

State			
	(904)	9,397	1,303
Total	$ (904)	$ 9,397	$ 1,303

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a reconciliation of the U.S. statutory income tax rate at 35% to our income (loss) before income taxes (in thousands):

	Year Ended December 31,		
	2006	**2005**	**2004**
Income (loss) from continuing operations			
Tax at U.S. statutory income tax	$ (5,106)	$ 13,144	$ 1,262
Nondeductible expenses	(14)	(5)	(6)
Valuation allowance and other		5	7,338
	(5,120)	13,144	8,594
Income (loss) from discontinued operations			
Tax at U.S. statutory income tax	4,216	(3,747)	(7,291)
	4,216	(3,747)	(7,291)
Total tax (expense) benefit	$ (904)	$ 9,397	$ 1,303

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2006 and 2005 are presented below (in thousands).

	2006	**2005**
Deferred tax assets:		
Differences between book and tax basis of:		
Operating loss carryforwards	$ 24,599	$ 16,064
Statutory depletion carryforward	7,034	7,034
AMT tax credit carryforward	1,480	1,480
Derivative financial instruments		10,263
Compensation	421	
Contingent liabilities and other	462	466
Total gross deferred tax assets	33,996	35,307
Less valuation allowance	(13,263)	(13,263)
Net deferred tax asset	20,733	22,044
Deferred tax liabilities:		
Differences between book and tax basis of:		
Property and equipment	(6,255)	(10,464)
Derivative financial instruments	(4,773)	
Total gross deferred tax liabilities	(11,028)	(10,464)

Net deferred tax asset	$ 9,705	$ 11,580

Our stock based deferred compensation plans generated $3.5 million of additional tax deductions in 2006 which are not recognized as a component of our deferred tax asset. We recognize the benefits from excess tax stock compensation deductions after the utilization of net operating loss carryforwards generated from operations. These excess tax benefits will be recorded as additional paid in capital when realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based primarily upon the level of projections for future taxable income and the reversal of future taxable temporary differences over the periods which the deferred tax assets are deductible, management believes it is more likely than not we will realize the benefits of our deferred tax assets, net of the existing valuation allowance at December 31, 2006.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have tax net operating loss carryforwards totaling $73.8 million which expire in years 2007 through 2026 as follows (in thousands):

2007	$ 7,894
2008	4,286
2009	3,247
2010	6,451
2011	
2012 through 2026	51,907
Total	$ 73,785

An ownership change in accordance with Internal Revenue Code (IRC) § 382, occurred in August 1995 and again in August 2000. The net operating losses (NOLs) generated prior to August 1995 are subject to an annual IRC § 382 limitation of $1.7 million. The IRC § 382 annual limitation for the ownership change in August 2000 is $3.6 million. The latter IRC § 382 ownership change limitation is a cumulative limitation and does not eliminate or increase the limitation on the pre- August 1995 NOLs. The NOLs generated after August 1995 and prior to August 2000, are subject to an annual limitation of $3.6 million less the annual amount utilized for pre-August 1995 NOLs. It should be noted that the same IRC § 382 limitations apply to the alternative minimum tax net operating loss carryforwards, depletion carryforwards, and alternative minimum tax credit carryforwards. The minimum tax credit carryforward (MTC) of $1.5 million as of December 31, 2006, will not begin to be utilized until after the available NOLs have been utilized or expired and when regular tax exceeds the current year alternative minimum tax. The unused annual IRC § 382 limitations can be carried over to subsequent years.

NOTE 7 Stockholders Equity

Common Stock At December 31, 2006, a total of 7,733,613 unissued shares of Goodrich common stock were reserved for the following: (a) 1,023,500 shares for the exercise of stock options; (b) 3,587,850 shares for the conversion of Series B convertible preferred stock; and (c) 3,122,263 shares for the conversion of the 3.25% convertible senior notes. Stock warrants issued in connection with a September 1999 private placement of convertible notes and subsidiary securities at exercise prices ranging from $0.9375 to $1.50 per share expired in September 2006. Each warrant was exercisable into one share of common stock upon payment of the exercise price, however, the holders of the stock warrants could, in certain circumstances, elect a cashless exercise whereby additional in the money warrants could be tendered to cover the exercise price of the warrants. Pursuant to a May 2003 stock purchase agreement, the holders of 2,369,527 warrants to purchase common stock elected a cashless exercise of such warrants resulting in the issuance of 2,109,169 shares of common stock in three separate installments which closed in January, April, and July 2004. There were no further exercises of warrants to be made pursuant to the stock purchase agreement; however, in February 2005, the holder of 330,000 warrants to purchase common stock elected to exercise such warrants by paying the exercise price in cash. As of December 31, 2006, none of said warrants remained outstanding.

In May 2005, we completed a public offering of 3,710,000 shares of our common stock at an offering price of $15.40 per share resulting in net proceeds of $53.1 million, after underwriting discount and offering costs. We used the proceeds to repay all outstanding indebtedness to BNP under our previous senior credit facility in the amount of $39.5 million with the balance being added to working capital to be used primarily to fund an accelerated drilling program in the Cotton Valley Trend of East Texas and Northwest Louisiana.

Share Lending Agreement With the offering of the 3.25% convertible senior notes we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock. The shares of stock were lent to the affiliate of BSC under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from all such common stock offerings and lending transactions under this agreement. We will not receive any of the proceeds from these transactions. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of shares pursuant to the terms of the 3.25% convertible notes offering.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The 3,122,263 shares of common stock outstanding as of December 31, 2006, under the Share Lending Agreement are required to be returned to the Company. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. There is no impact of the shares of common stock lent under the Share Lending Agreement in the earnings per share calculation.

Preferred Stock Our Series A Convertible Preferred Stock (the Series A Convertible Preferred Stock) has a par value of $1.00 per share with a liquidation preference of $10.00 per share, aggregating to $7.9 million, and is convertible at the option of the holder at any time, unless earlier redeemed, into shares of our common stock at an initial conversion rate of 0.4167 shares of common stock per share of Series A Convertible Preferred Stock. The Series A Convertible Preferred Stock also will automatically convert to common stock if the closing price for the Series A Convertible Preferred Stock exceeds $15.00 per share for ten consecutive trading days. The Series A Convertible Preferred Stock is redeemable in whole or in part, at $12.00 per share, plus accrued and unpaid dividends. Dividends on the Series A Convertible Preferred Stock accrue at an annual rate of 8% and are cumulative. In February 2006, we fully redeemed all issued and outstanding shares of our Series A Convertible Preferred Stock at a net cost of approximately $9.3 million.

Our Series B Convertible Preferred Stock (the Series B Convertible Preferred Stock) was initially issued on December 21, 2005, in a private placement of 1,650,000 shares for net proceeds of $79.8 million (after offering costs of $2.7 million). Each share of the Series B Convertible Preferred Stock has a liquidation preference of $50 per share, aggregating to $82.5 million, and bears a dividend of 5.375% per annum. Dividends are payable quarterly in arrears beginning March 15, 2006. If we fail to pay dividends on our Series B Convertible Preferred Stock on any six dividend payment dates, whether or not consecutive, the dividend rate per annum will be increased by 1.0% until we have paid all dividends on our Series B Convertible Preferred Stock for all dividend periods up to and including the dividend payment date on which the accumulated and unpaid dividends are paid in full.

Each share is convertible at the option of the holder into our common stock, par value $0.20 per share (the Common Stock) at any time at an initial conversion rate of 1.5946 shares of Common Stock per share, which is equivalent to an initial conversion price of approximately $31.36 per share of Common Stock. Upon conversion of the Series B Convertible Preferred Stock, we may choose to deliver the conversion value to holders in cash, shares of Common Stock, or a combination of cash and shares of Common Stock.

On or after December 21, 2010, we may, at our option, cause the Series B Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock that are issuable at the then-prevailing conversion rate, pursuant to the Company Conversion Option. We may exercise our conversion right only if, for 20 trading days within any period of 30 consecutive trading days ending on the trading day prior to the announcement of our exercise of the option, the closing price of the Common Stock equals or exceeds 130% of the then-prevailing conversion price of the Series B Convertible Preferred Stock. The Series B Convertible Preferred Stock is non-redeemable by us.

We used the net proceeds of the offering of Series B Convertible Preferred Stock to fully repay all outstanding indebtedness under our senior revolving credit facility. The remaining net proceeds of the offering were added to our working capital to fund 2006 capital expenditures and for other general corporate purposes.

On January 23, 2006, the initial purchasers of 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, which was used to fund our 2006 capital expenditure program.

NOTE 8 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 December 31, 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 difference changes in the NYMEX contract terms and the physical location, grade and quality of our oil and gas production. As of December 31, 2006, our open forward positions on our outstanding commodity hedging contracts, all of which were with either BNP or Bank of Montreal (BMO), was as follows:

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Swaps	**Volume**	**Average Price**
Natural gas (MMBtu/day)		
1Q 2007	10,000	$ 7.77
Oil (Bbl/day)		
1Q 2007	400	$53.35
2Q 2007	400	53.35
3Q 2007	400	53.35
4Q 2007	400	53.35

Collars	**Volume**	**Floor/Cap**	
Natural gas (MMBtu/day)			
1Q 2007	10,000	$ 9.00	$10.65
2Q 2007	10,000	9.00	$10.65
3Q 2007	10,000	9.00	$10.65
4Q 2007	10,000	9.00	$10.65
1Q 2007	15,000	$ 7.00	$13.60
2Q 2007	15,000	7.00	$13.60
3Q 2007	15,000	7.00	$13.60
4Q 2007	15,000	7.00	$13.60
2Q 2007	5,000	$ 7.00	$13.90
3Q 2007	5,000	7.00	$13.90
4Q 2007	5,000	7.00	$13.90
Oil (Bbl/day)			
1Q 2007	400	$60.00	$76.50
2Q 2007	400	$60.00	$76.50
3Q 2007	400	$60.00	$76.50
4Q 2007	400	$60.00	$76.50

The fair value of the oil and gas hedging contracts in place at December 31, 2006, resulted in a net asset of $13.4 million. As of December 31, 2006, $1.2 million (net of $0.6 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 year ended December 31, 2006, we recognized in earnings a gain from derivatives not qualifying for hedge accounting in the amount of $38.1 million (also included in this gain amount are settlement payments on ineffective gas and oil hedges totaling $2.1 million in 2006). This gain was recognized because our gas hedges were deemed to be ineffective for 2006, and all of our oil hedges were deemed ineffective in the fourth quarter of 2006, accordingly, the changes in fair value of such hedges could no longer be reflected in other comprehensive loss. In the fourth quarter of 2006, we reclassified $0.7 million of previously deferred losses (net of $0.4 million in income taxes) from accumulated other comprehensive loss to loss on derivatives not qualifying for hedge accounting as the cash flow of the hedged items was recognized.

For the year ended December 31, 2006, we realized effective oil hedge losses of $3.5 million all related to our South Louisiana properties which are recognized in Discontinued Operations on the Consolidated Statements of Operations. See Note 12 Acquisitions and Divestitures to our consolidated financial statements for a further discussion of our discontinued operations.

Subsequent to year end, we unwound the oil collar for 400 barrels per day referenced above. As a result, we expect to recognize a gain of $0.9 million in the first quarter of 2007. Subsequent to year end, we have entered into a series of physical sales contracts which will result in us selling approximately 18,500 MMbtu of gas per day in calendar year 2008 for an average price of $8.01 MMbtu before transportation charges.

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.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
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Interest Rate Swaps

We have a variable-rate debt obligation that exposes 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 December 31, 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
02/27/07	02/26/09	4.86%	40.0

The fair value of the interest rate swap contracts in place at December 31, 2006, resulted in an asset of $0.2 million. For the years ended December 31, 2006 and 2005, our earnings were not significantly affected by cash flow hedging ineffectiveness of the interest rates swaps.

NOTE 9 Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments* (SFAS 107). The estimated fair value amounts have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. The carrying amounts and fair values of the other financial instruments and derivatives at December 31, 2006 and 2005, are as follows (in thousands):

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Second Lien Term Loan	$ 0	$ 0	$ 30,000	$ 30,000
Senior Credit Facility	26,500	26,500		
3.25% Convertible Senior Notes	175,000	170,240		
Derivative assets (liabilities)				
Oil	(1,446)	(1,446)	(4,810)	(4,810)
Gas	14,865	14,865	(24,620)	(24,620)
Interest rate	219	219	107	107

NOTE 10 Commitments and Contingencies

Operating Leases We have commitments under an operating lease agreement for office space. Total rent expense for the years ended December 31, 2006, 2005, and 2004, was approximately $0.6 million, $0.4 million, and $0.3 million respectively. We also have non-cancellable drilling rig commitments with various term end dates through 2009.

Transportation Contracts We have entered into two gas gathering and processing agreements where we are obligated to pay a minimum amount, as calculated on a yearly amount, or pay deficiencies at a specified gathering fee rate. Our production committed to these contracts is expected to exceed the minimum yearly volumes provided in the contracts, therefore avoiding payments for deficiencies.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2007 we purchased acreage that was committed to a gas gathering agreement where we have a four year obligation to pay a minimum amount, as calculated on a yearly amount, or pay deficiencies at a specified gathering fee rate. The first year of the contract commitment began on September 1, 2006. Our potential share of the minimum yearly amount ranges from approximately $0.1 million in the first year to approximately $0.5 million in the fourth year. The potential effect of this agreement is not included in the table below since our share of the commitment will not be determined until well(s) are drilled in 2007.

At December 31, 2006, future minimum rental payments due, drilling rig commitments, and transportation contract commitments are as follows:

	Payments due by Period						
	Total	2007	2008	2009	2010	2011	After 2011
Operating lease for office space	$ 1,992	$ 701	$ 710	$ 491	$ 48	$ 42	$
Drilling rig commitments	80,247	45,983	24,956	9,308			
Transportation contracts	2,159	758	540	540	321		
Total (1)	$ 84,398	$ 47,442	$ 26,206	$ 10,339	$ 369	$ 42	$

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $9.6 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3.

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.

Litigation In the third quarter of 2004, we recognized a non-recurring gain in the amount of $2.1 million, reflecting the proceeds of a successful litigation judgment. We commenced the litigation as plaintiff in February 2000 against the operator of a South Louisiana property which was jointly acquired by us and the defendant in September 1999.

The judgment provided for recovery of our damages and a portion of our attorneys fees as well as interest calculated on our damages.

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 11 Related Party Transactions

On March 12, 2002, we completed the sale of a 30% working interest in the existing production and shallow rights, and a 15% working interest in the deep rights below 10,600 feet, in our Burrwood and West Delta 83 fields for $12.0 million to Malloy Energy Company, LLC (MEC), led by Patrick E. Malloy, III and participated in by Sheldon Appel, each of whom were members of our Board of Directors at that time, as well as Josiah Austin, who subsequently became a member of our Board of Directors. Mr. Malloy is now Chairman of our Board of Directors and Mr. Appel retired from the Board of Directors in February 2004.

Subsequent to the acquisition of a 30% working interest in the Burrwood and West Delta 83 fields in March 2002, MEC acquired an approximate 30% working interest in three other fields we operated in 2003 and 2004. In accordance with industry standard joint operating agreements, we bill MEC for its share of the capital and operating costs of the three fields on a monthly basis. As of December 31, 2006 and 2005, the amounts billed and outstanding to MEC for its share of monthly capital and operating costs were $1.3 million and $0.5 million, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by MEC to us in the month subsequent to billing and the affiliate is current on payment of its billings.

We also serve as the operator for a number of other oil and gas wells owned by an affiliate of MEC in which we own a 7% after payout working interest. In accordance with industry standard joint operating agreements, we bill the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2006 and 2005, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were $19,000 and $78,000, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to us in the month subsequent to billing and the affiliate is current on payment of its billings.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additionally, we also serve as the operator for a number of other oil and gas wells owned by an affiliate of MEC whereby we do not have a working interest. In accordance with industry standard joint operating agreements, we bill the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2006 and 2005, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were $81,000 and $272,000, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to us in the month subsequent to billing and the affiliate is current on payment of its billings.

NOTE 12 Acquisitions and Divestitures

On February 7, 2007, we announced the acquisition of drilling and development rights to acreage located in the Angelina River play. We acquired a 60% working interest in the acreage and will operate the joint venture. The acquisition was completed in two separate transactions. In the initial transaction, we acquired a 40% working interest for $2.0 million from a private company. We also agreed to carry the private company for a 20% working interest in the drilling of five wells. In the second transaction, we are purchasing the remaining 20% working interest in the acreage in a like-kind exchange for our 30% interest in the Mary Blevins field.

On December 6, 2006, we closed on the acquisition of additional interests in the Dirgin-Beckville field in the Cotton Valley Trend for $6.1 million from a private company. With this acquisition, we now own an approximate 99% working interest in this field.

Discontinued Operations

On January 12, 2007, the Company and Malloy Energy entered into a Purchase and Sale Agreement with a private company for the sale of substantially all of the Company s oil and gas properties in South Louisiana. The total sales price for the company s interest in the oil and gas properties was approximately $100 million, effective July 1, 2006. The total sales price for Malloy Energy s interests in these properties was approximately $30 million with the same effective date. See Note 11 Related Party Transactions for additional information regarding Malloy Energy. Both the Company and Malloy Energy s total consideration was reduced by an amount equal to its proportionate share of the greater of $20 million or normal closing adjustments. The adjusted sales price for the Company s interest was $77 million. The effective date of the transaction was July 1, 2006 and the closing date of the sale was late March, 2007. Subsequent to December 31, 2006, the company s interest in oil and gas properties in South Louisiana met the criteria for reporting as held for sale. The company completed the sale in the first quarter of 2007. Mr. Malloy is Chairman of our Board of Directors. The carrying value of the assets and liabilities disposed of was $62 million consisting of $131 million in property, plant and equipment, less $63 million in accumulated depreciation, depletion and amortization and $6 million in asset retirement obligation liabilities.

In October 2004, we sold our operated interests in the Marholl and Sean Andrew fields, along with our non-operated interests in the Ackerly field, all of which were located in West Texas, for gross proceeds of approximately $2.1 million. We realized a gain of $0.9 million on the sale of these non-core properties.

In accordance with SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets , the results of operations and gain relating to these divested properties and for the properties held for sale have been reflected as discontinued operations. Note 6 Income Taxes has been revised as a result of discontinued operations.

Results for these properties reported as discontinued operations were as follows (in thousands):

	For the Years Ended December 31,		
	2006	2005	2004
	(in thousands)		
Revenues	$ 41,383	$34,092	$41,668
Income (loss) from discontinued operations	(11,876)	10,707	20,830
Income tax benefit (expense)	4,216	(3,747)	(7,291)
Income (loss) from discontinued operations net of tax	(7,660)	6,960	13,539

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 13 Oil and Gas Producing Activities (Unaudited)

Capitalized Costs Related to Oil and Gas Producing Activities

The table below reflects our capitalized costs related to oil and gas producing activities at December 31, 2006, and 2005 (in thousands):

	2006	2005
Proved properties	$ 555,013	$ 301,842
Unproved properties	20,653	14,444
	575,666	316,286
Less accumulated depreciation, depletion and amortization	(155,204)	(73,291)
Net oil and gas properties	$ 420,462	$ 242,995

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Property Acquisition			
Unproved	$ 8,569	$ 9,216	$ 5,528
Proved	6,120		
Exploration	12,263	14,021	4,874
Development (1)	244,240	143,574	36,351
	$ 271,192	$ 166,811	$ 46,753

(1) Includes asset retirement costs of $1.3 million in 2006, $1.1 million in 2005 and $0.4 million in 2004.

Oil and Natural Gas Reserves

All of our reserve information related to crude oil, condensate, and natural gas liquids and natural gas was compiled based on evaluations performed by Netherland, Sewell & Associates, Inc. as of December 31, 2006 and 2005. All of the subject reserves are located in the continental United States.

Many assumptions and judgmental decisions are required to estimate reserves. Quantities reported are considered reasonable but are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional knowledge may be gained as the result of reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, and other factors.

Regulations published by the SEC define proved reserves as those volumes of crude oil, condensate, and natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those volumes expected to be recovered as a result of making additional investments by drilling new wells on acreage offsetting productive units or recompleting existing wells.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth our net proved oil and gas reserves at December 31, 2006, 2005 and 2004 and the changes in net proved oil and gas reserves for the years ended December 31, 2006, 2005 and 2004:

	Natural Gas (MMcf)			Oil (MBbls)		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Proved Reserves at beginning of period	142,963	67,682	30,903	4,973	5,589	7,805
Revisions of previous estimates (1)	(66,409)	(10,382)	(6,666)	(1,612)	(648)	(3,466)
Extensions, discoveries and other additions (2)	115,732	91,900	48,322	311	440	1,987
Purchases of minerals in place	7,727			3		
Sales of minerals in place			(54)			(249)
Production	(13,001)	(6,237)	(4,823)	(474)	(408)	(488)
Proved Reserves at end of period	187,012	142,963	67,682	3,201	4,973	5,589

	Natural Gas (MMcf)			Oil (MBbls)		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Proved developed:						
Beginning of period	56,700	24,362	23,429	1,796	2,228	3,601
End of period	76,679	56,700	24,362	1,862	1,796	2,228

(1) Revisions of previous estimates were negative on an overall basis in 2006, 2005 and 2004 related to the following: (a) with respect to 2006, the primary cause of the revisions was the significant pricing difference between December 31, 2006 and

December 31, 2005, which caused a number of our proved undeveloped locations in the Cotton Valley area to become uneconomic at the lower prices, as well as some volume revisions in these same properties and in South Louisiana as a result of updated production performance, and (b) with respect to 2005 and 2004, the premature depletion or decline in production from our South Louisiana wells which had larger estimates of producible reserves at the previous reporting period and new and/or revised interpretations of technical data from recently drilled wells in that region, updated production performance from existing and offset wells, and/or the results of enhanced 3-D seismic evaluations.

(2) Extensions, discoveries and other reserve additions were positive on an overall basis in 2006, primarily related to our continued drilling activities on existing and newly acquired properties in the Cotton Valley Trend of East Texas and North Louisiana. The main reason for the increases in 2005 and 2004 was the commencement of our Cotton Valley drilling program in the first quarter of 2004 which resulted in a substantial volume of both proved developed and proved undeveloped reserves being recorded in those years.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes our combined oil and gas reserve information on an MMcfe basis.

	Year Ended December 31,		
	2006	**2005**	**2004**
Total proved	206,217	172,799	101,216
Proved developed	87,852	67,474	37,732

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves as of year-end is shown below (in thousands):

	2006	**2005**	**2004**
Future revenues	$ 1,190,367	$ 1,798,972	$ 654,543
Future lease operating expenses and production taxes	(409,775)	(379,872)	(151,186)
Future development costs (1)	(337,576)	(245,868)	(86,919)
Future income tax expense	(28,764)	(353,472)	(104,870)
Future net cash flows	414,252	819,760	311,568
10% annual discount for estimated timing of cash flows	(213,971)	(409,140)	(130,890)
Standardized measure of discounted future net cash flows	$ 200,281	$ 410,620	$ 180,678
Average price used to calculate reserves (2)			
Natural gas (per Mcf)	$ 5.64	$ 10.54	$ 6.14
Oil (per Bbl)	$ 57.75	$ 58.80	$ 42.72

(1) Includes cumulative asset retirement obligations of $9.6 million, $8.0 million and $6.8 million in 2006, 2005 and 2004, respectively.

(2) These average prices, used to estimate our reserves at these dates, reflect applicable transportation and quality

differentials on a well-by-well basis.

Future revenues are computed by applying year-end prices of oil and gas to the year-end estimated future production of proved oil and gas reserves. The base prices used for the PV-10 calculation were public market prices on December 31 adjusted by differentials to those market prices. These price adjustments were done on a property-by-property basis for the quality of the oil and natural gas and for transportation to the appropriate location. Estimates of future development and production costs are based on year-end costs and assume continuation of existing economic conditions and year-end prices. We will incur significant capital in the development of our Cotton Valley Trend properties. We believe with reasonable certainty that we will be able to obtain such capital in the normal course of business. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted cash flows is the future net cash flows less the computed discount.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure

The following are the principal sources of change in the standardized measure of discounted net cash flows for the years shown (in thousands):

	Year Ended December 31,		
	2006	**2005**	**2004**
Net changes in prices and production costs related to future production	$ (360,635)	$ 185,709	$ 84,156
Sales and transfers of oil and gas produced, net of production costs	(81,813)	(53,845)	(34,354)
Net change due to revisions in quantity estimates	(70,212)	(48,540)	(27,462)
Net change due to extensions, discoveries and improved recovery	122,144	321,529	60,239
Net change due to purchases and sales of minerals in place	8,044		(4,278)
Future development costs	(44,339)	(79,618)	(53,739)
Net change in income taxes	142,131	(124,526)	(22,640)
Accretion of discount	58,768	24,148	21,462
Change in production rates (timing) and other	15,573	5,085	(6,680)
	$ (210,339)	$ 229,942	$ 16,704

NOTE 14 Summarized Quarterly Financial Data (Unaudited)

(In Thousands, Except Per Share Amounts)

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2006					
Revenues	$14,769	$20,154	$ 19,624	$ 20,224	$ 74,771
Operating income (loss)	577	(248)	(2,166)	(13,415)	(15,252)(2)
Income (loss) from continuing operations	8,726	2,719	6,844	(8,990)	9,299
Income (loss) from discontinued operations, net of tax	2,866	1,579	1,337	(13,442)	(7,660)
Net income (loss)	11,592	4,298	8,181	(22,432)	1,639(2)
Net income (loss) applicable to common stock	8,575	2,777	6,670	(23,944)	(5,922)
Basic income (loss) per average common share (1)	0.47	0.17	0.33	(0.90)	0.07
Diluted income (loss) per average common share (1)	0.46	0.17	0.32	(0.90)	0.06
2005					
Revenues	$ 3,435	$ 4,796	$ 8,811	$ 18,269	$ 35,311
Operating income (loss)	(2,388)	(2,348)	38	7,183	2,485
Income (loss) from continuing operations	(8,152)	(2,039)	(21,425)	7,206	(24,410)
Income from discontinued operations, net of tax	2,001	1,594	1,951	1,414	6,960

Net income (loss)	(6,151)	(445)	(19,474)	8,620	(17,450)[3]
Net income (loss) applicable to common stock	(6,309)	(603)	(19,632)	8,339	(18,205)[3]
Basic income (loss) per average common share (1)	(0.30)	(0.02)	(0.79)	0.35	(0.75)
Diluted income (loss) per average common share (1)	(0.30)	(0.02)	(0.79)	0.34	(0.75)

(1) The sum of the per share amounts per quarter does not equal the year due to the changes in the average number of common shares outstanding.

(2) Includes a $40.2 million unrealized gain on derivatives not qualifying for hedge accounting.

(3) Includes a $27.0 million unrealized loss on derivatives not qualifying for hedge accounting.

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ITEM 9.01. FINANCIAL STATEMENTS AND EXHIBITS

(d) Exhibits:

Exhibit Number	Description
12.1	Ratio of Earnings to Fixed Charges
12.2	Ratio of Earnings to Fixed Charges and Preference Securities Dividends
23.1	Consent of KPMG LLP
23.2	Consent of Netherland, Sewell & Associates, Inc.

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SIGNATURES

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

GOODRICH PETROLEUM CORPORATION
(Registrant)

/s/ David R. Looney

David R. Looney
Executive Vice President & Chief Financial Officer

Dated: August 7, 2007

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EXHIBIT INDEX

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