GOODRICH PETROLEUM CORP
Form 10-K
February 27, 2009

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2008

OR

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

Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
808 Travis, Suite 1320 Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

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

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, par value $0.20 per share	New York Stock Exchange
(Title of Class)	***(Name of Exchange)***

Securities Registered Pursuant to Section 12(g) of the Act:

Series B Preferred Stock, $1.00 par value

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Small reporting company ¨

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

The aggregate market value of Common Stock, par value $0.20 per share (Common Stock), held by non-affiliates (based upon the closing sales price on the New York Stock Exchange National Market on June 30, 2008) the last business day of the registrant s most recently completed second fiscal quarter was approximately $1.7 billion. The number of shares of the registrant s common stock outstanding as of February 25, 2009 was 37,631,407.

Documents Incorporated By Reference:

Portions of Goodrich Petroleum Corporation s definitive Proxy Statement are incorporated by reference in Part III of this Form 10-K.

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GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2008

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PART I

Items 1 and 2. ***Business and Properties***

General

Goodrich Petroleum Corporation and its subsidiaries (together, we or the Company) is 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, including the recently discovered Haynesville Shale play in the same region. We own working interests in 414 active oil and gas wells located in thirty fields in six states. At December 31, 2008, we had estimated proved reserves of approximately 390.4 Bcf of natural gas and 1.9 MMBbls of oil and condensate, or an aggregate of 402.3 Bcfe with a pre-tax present value of future net cash flows, discounted at 10%, or PV-10, of $169.8 million and a related standardized measure of discounted future net cash flows of $167.4 million, which reflects the after-tax present value of discounted future net cash flows. See the table included in the Oil and Natural Gas Reserves section on page 7 for a reconciliation of PV-10 to the standardized measure of discounted future net cash flows.

Our principal executive offices are located at 808 Travis Street, Suite 1320, Houston, Texas 77002.

2008 Highlights

We achieved annual production volume growth of 51% with production growing from 16.0 Bcfe in 2007 to 24.2 Bcfe in 2008.

We entered into an agreement with Chesapeake Energy Corporation, or Chesapeake, to jointly develop a portion of our Haynesville Shale acreage in Northwest Louisiana. We sold a portion of our interest in the Haynesville Shale deep rights at the Bethany Longstreet and Longwood fields to Chesapeake for net proceeds of $172.0 million resulting in a gain of $145.1 million. Chesapeake serves as operator for these properties.

We established our presence in the Haynesville Shale play in Northwest Louisiana and East Texas and increased our ownership to approximately 63,000 net acres at December 31, 2008.

We drilled and completed 126 gross (75.4 net) wells in 2008, with a success rate of 98%.

We raised net proceeds of $191.3 million from our equity offering in July 2008 and paid down all of the outstanding borrowings under our senior credit facility. We ended the year with $147.5 million in cash and short term investments.

Estimated proved reserves grew 12% to approximately 402.3 Bcfe (approximately 390.4 Bcf of natural gas and 1.9 MMBbls of oil and condensate), with a PV-10 of $169.8 million and a standardized measure of $167.4 million, approximately 38% of which is developed.

2008 Haynesville Shale Transactions

Chesapeake Haynesville Joint Development

On June 16, 2008, we entered into a joint development agreement with Chesapeake to develop our Haynesville Shale acreage in the Bethany Longstreet and Longwood fields of Caddo and DeSoto Parishes, Louisiana. Chesapeake purchased the deep rights, including the Haynesville Shale, to approximately 10,250 net acres of oil and natural gas leasehold comprised of a 20% working interest in approximately 25,000 net acres in the Bethany Longstreet field and a 50% working interest in approximately 10,500 net acres in the Longwood field for net proceeds of $172.0 million. Chesapeake also purchased 7,500 net acres of deep rights in the Bethany Longstreet field from a third party (see Note 11 Related Party Transactions to our consolidated financial statements), bringing the ownership interest in the deep rights in both fields after closing to 50% each for us and

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Chesapeake. Chesapeake is the operator of the joint Haynesville Shale development. As a result of this transaction, we hold approximately 25,000 gross (12,500 net) acres in the deep rights in the Bethany Longstreet field and approximately 10,500 gross (5,250 net) acres in the deep rights in the Longwood field, both of which are currently believed to be prospective for the Haynesville Shale. Through our joint development arrangement with Chesapeake, we will continue to operate existing production and operate any new wells drilled to the base of the Cotton Valley sand, and Chesapeake will operate any wells drilled below the base of the Cotton Valley sand, including the Haynesville Shale.

We retained the shallow rights to the base of the Cotton Valley sand and the existing production and reserves with respect to our 70% working interest in the Bethany Longstreet field and our 100% working interest in the Longwood field. We also retained our interest in both the shallow and Haynesville Shale rights on all of our East Texas assets. During the third quarter of 2008, Chesapeake began drilling the Holland 17H No.1 as the first horizontal well on the joint acreage in Bethany Longstreet field. In the Longwood field, Chesapeake re-entered the Lona Johnson No. 1 drilling it to the deeper Haynesville Shale and recovered 154 feet of core from the formation to evaluate. During the fourth quarter of 2008, completion operations began on both of these wells and two horizontal Haynesville Shale development wells were spud in Bethany Longstreet field, together with two Haynesville Shale wells in Longwood field. In 2009, we and Chesapeake plan to use an average of approximately three rigs to drill 22 gross wells.

Caddo Parish Acquisition

On May 28, 2008, we acquired additional interests in the Cotton Valley trend, increasing our net exposure in the Haynesville Shale. We acquired approximately 3,665 net acres in Longwood field of Caddo Parish, Louisiana, through the issuance of 908,098 shares of our common stock valued at approximately $33.9 million. The purchase included interests in 25 gross wells, with approximately 1.1 Mmcfe per day of net production, and 5.2 Bcfe of proved reserves (77% developed) associated with the shallower Hosston and Cotton Valley formations. As of December 31, 2008, we had drilled and participated in three Haynesville wells.

Caddo Pine Island Acquisition

On June 10, 2008, we entered into a definitive agreement with a private company for the right to acquire over time a 50% non-operated interest in 5,800 gross (2,900 net) acres in the Caddo Pine Island field, north of and adjacent to our Longwood field in Caddo Parish, Louisiana. Total consideration paid was approximately $3.3 million, which was comprised of acreage costs for the 50% interest in the leasehold and the cost of a carried interest on the initial well drilled on the acreage. As of December 31, 2008, four wells had been drilled vertically to the Haynesville Shale on this acreage. In the fourth quarter of 2008, we re-entered two of these wells to drill them horizontally in the Haynesville Shale formation. Completion of the first horizontal well will start in the first quarter of 2009 and we expect to complete the other wells in the second quarter of 2009. In 2009, we plan to drill two additional horizontal Haynesville Shale wells on the acreage.

In connection with the Chesapeake joint development agreement, the Caddo Parish Acquisition and the Caddo Pine Island Acquisition, we have a total of approximately 22,000 net acres in North Louisiana which we believe to be prospective for the Haynesville Shale formation.

Initial Company Operated Haynesville Shale Drilling Program

As of December 31, 2008, we have been the operator on and drilled four vertical wells on our North Louisiana acreage and seven wells on our East Texas acreage, for a total of eleven vertical wells targeting the Haynesville Shale. In the fourth quarter of 2008, we began drilling our first operated horizontal Haynesville Shale well. We expect to complete this well in the first quarter of 2009. We expect that our development of the Haynesville Shale will continue in 2009 with the drilling and completion of nine company operated horizontal wells in East Texas.

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Business Strategy

Our business strategy is to provide long term growth in net asset value per share, through the growth and expansion of our oil and gas production and reserves. We focus on adding reserve value through the development of our Haynesville Shale acreage and the timely development of our large relatively low risk development program in the Cotton Valley trend. We continue to pursue the acquisition and evaluation of prospective acreage, oil and gas drilling opportunities and potential property acquisitions.

Several of the key elements of our business strategy are the following:

Exploit and Develop Existing Property Base. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest production and reserve growth potential. We intend to concentrate on developing our multi-year inventory of drilling locations in the Haynesville Shale and Cotton Valley trend in order to develop our natural gas reserves in East Texas and Northwest Louisiana. We estimate that our Haynesville Shale acreage currently includes as many as 1,000 gross unrisked, non-proved drilling locations and our Cotton Valley trend inventory includes as many as 2,200 gross unrisked, non-proved drilling locations based on anticipated well spacing.

Expand Acreage Position in the Haynesville Shale and Cotton Valley trend. We have increased our acreage position in the Cotton Valley trend from approximately 181,600 gross (114,800 net) acres at December 31, 2007 to approximately 203,300 gross (127,200 net) acres as of December 31, 2008. We continue to concentrate our efforts in areas where we can apply our technical expertise and where we have significant operational control or experience. To leverage our extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in the Haynesville Shale and Cotton Valley trend that exhibits similar characteristics to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

Focus on Low Operating Costs. As we continue to develop our properties, we expect our overall operating costs per Mcfe to decrease, due primarily to our continued efforts to reduce saltwater disposal costs through the installation of field disposal systems, as well as an increasing mix of Haynesville Shale production. Production from the Haynesville Shale is not expected to be as water intensive as production from the Cotton Valley trend and Travis Peak geological formations, thereby reducing our per unit lease operating expenses. Additionally, in March 2007, we sold most of our assets in South Louisiana which had higher operating costs than our Cotton Valley trend properties.

Maintain an Active Hedging Program. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically fixed price swaps and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Use of Advanced Technologies. We continually perform field studies of our existing properties and reevaluate exploration and development opportunities using advanced technologies. For example, we recently commenced drilling our initial company operated horizontal Haynesville Shale well and continue to test horizontal drilling in the Cotton Valley and James Lime formations.

Oil and Gas Operations and Properties

Cotton Valley Trend and Haynesville Shale

Overview. As of December 31, 2008, nearly all of our proved oil and gas reserves were in the Cotton Valley trend of East Texas and Northwest Louisiana. We spent nearly all of our 2008 capital expenditures of

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$380.1 million in the Cotton Valley trend and the Haynesville Shale. Our total capital expenditures, including accrued expenses for services performed during 2008, consist of $345.8 million for drilling and completion costs, $28.6 million for leasehold acquisition, $4.5 million for facilities and infrastructure and $1.2 million for furniture, fixtures and equipment.

As of December 31, 2008, we have acquired or farmed-in leases totaling approximately 203,300 gross (127,200 net) acres and are continually attempting to acquire additional acreage in the area. Company-operated acreage comprised 150,900 gross acres (with an average working interest of approximately 91%) and non-operated acreage comprised 52,400 gross acres (with an average working interest of approximately 37%). During 2008, we had drilled and completed 126 Cotton Valley trend wells, including 19 Haynesville Shale wells with a success rate in excess of 98%. Our current Cotton Valley trend and Haynesville Shale drilling activities are located in six primary leasehold areas in East Texas and Northwest Louisiana.

The table below details our acreage holdings, average working interest and wells drilled and completed through the base of the Cotton Valley formation.

Field or Area	Acreage As of December 31, 2008 Gross	Acreage As of December 31, 2008 Net	Average Working Interest	Wells Drilled and Completed As of December 31, 2008 Successful	Wells Drilled and Completed As of December 31, 2008 Unsuccessful
North Minden	31,763	28,011	93%	115	2
Dirgin-Beckville	12,339	11,774	99%	75	2
Angelina River	82,607	41,561	66%	88	1
South Henderson	11,748	8,995	97%	35	
Bethany-Longstreet	28,855	19,430	69%	52	
Longwood	21,364	10,723	57%	27	
Caddo Pine Island	6,400	2,900	52%	5	
Other Cotton Valley trend	6,135	3,551	55%	17	1
Total Cotton Valley	201,211	126,945	81%	414	6
Other	2,134	227	35%		
Total	203,345	127,172	79%	414	6

In those fields or areas where we have made the determination that the Haynesville Shale is productive, these are our acreage positions, average working interest and wells drilled and completed in the Haynesville Shale.

Field or Area	Haynesville Acreage As of December 31, 2008 Gross	Haynesville Acreage As of December 31, 2008 Net	Average Working Interest	Wells Drilled and Completed As of December 31, 2008 Successful	Wells Drilled and Completed As of December 31, 2008 Unsuccessful
North Minden	31,642	27,890	100%	5	
Dirgin-Beckville	12,339	11,774	100%	1	
Angelina River	8,314	2,467	50%	1	
South Henderson			100%	1	
Bethany-Longstreet	28,855	12,334	56%	4	
Longwood	10,723	5,361	50%	2	

Caddo Pine Island	6,400	2,900	52%	5
Other	1,920	544	48%	
Total Haynesville Shale	100,193	63,270	71%	19

Production and Reserves. For the wells completed to date in the Cotton Valley trend, the average initial gross production rate per well was approximately 2,199 Mcfe per day. Initial production from the Cotton Valley trend wells commenced in June 2004. Gross production averaged approximately 123,715 Mcfe/d and net production averaged approximately 70,442 Mcfe/d for the fourth quarter of 2008.

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Field or Area	December 31, 2008 Proved Reserves (Mmcfe)	% of Total	Fourth Quarter 2008 Net Average Daily Production (Mcfe/d)	% of Total
North Minden	132,934	33%	20,319	29%
Dirgin-Beckville	97,255	24%	10,837	15%
Angelina River	97,087	24%	20,760	29%
South Henderson	32,559	8%	7,993	11%
Bethany-Longstreet	31,286	8%	7,100	10%
Longwood	5,226	1%	1,100	2%
Caddo Pine Island				
Other Cotton Valley trend	3,279	1%	2,333	3%
Total Cotton Valley trend and Haynesville Shale	399,626	99%	70,442	99%
Other	2,723	1%	301	1%
Total	402,349	100%	70,743	100%

Other Properties

In March 2007, we sold substantially all of our oil and gas properties in South Louisiana. The sale resulted in net proceeds of $72.3 million, after normal closing adjustments. We continue to treat the Plumb Bob field in South Louisiana as held for sale, which represents less than 1% of our total equivalent proved reserves at December 31, 2008.

As of December 31, 2008, we maintain ownership interests in acreage and/or wells in several additional fields including: the Midway field in San Patricio County, Texas; the Mott Slough field in Wharton County, Texas and the Garfield Unit in Kalkaska County, Michigan.

Oil and Natural Gas Reserves

The following tables set forth summary information with respect to our proved reserves as of December 31, 2008 and 2007, as estimated by us by compiling reserve information derived from the evaluations performed by Netherland, Sewell & Associates, Inc. (NSA), our independent reserve engineers. See Note 15 Oil and Gas Producing Activities (Unaudited) to our consolidated financial statements for additional information. We did not file any reports during the year ended December 31, 2008, with any federal authority or agency with respect to our estimates of oil and natural gas reserves.

	Proved Reserves at December 31, 2008			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	316	71	1,596	1,983
Natural Gas (MMcf)	130,746	19,428	240,276	390,449

Natural Gas Equivalent (MMcfe)	132,643	19,852	249,854	402,349
Estimated Future Net Cash Flows				$ 560,007
Present Value of Future Net Cash Flows (before income taxes) (1)				$ 169,844
Discounted Future Income Taxes				(2,401)
Standardized Measure of Discounted Net Cash Flows (1)				$ 167,443

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	Proved Reserves at December 31, 2007			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	252	31	1,528	1,810
Natural Gas (MMcf)	94,049	14,026	238,855	346,930
Natural Gas Equivalent (MMcfe)	95,559	14,211	248,023	357,792
Estimated Future Net Cash Flows				$ 894,958
Present Value of Future Net Cash Flows (before income taxes) (1)				$ 312,684
Discounted Future Income Taxes				(28,567)
Standardized Measure of Discounted Net Cash Flows (1)				$ 284,117

(1) PV-10 represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. Our standard measure of discounted future net cash flows of proved reserves, or standardized measure, as of December 31, 2008 was $167.4 million. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.

Reserve engineering is a subjective process of estimating underground accumulations of crude oil, condensate and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Therefore, the PV-10 amounts shown above should not be construed as the current market value of the oil and natural gas reserves attributable to our properties.

In accordance with the guidelines of the SEC, our independent reserve engineers estimates of future net revenues from our properties and the PV-10 and standardized measure thereof are made using oil and natural gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The index prices as of December 31, 2008 and 2007, used in such estimates averaged $5.71 and $6.80 per Mmbtu, respectively, of natural gas and $41.00 and $92.50 per Bbl, respectively, of crude oil/condensate. These prices do not include the impact of hedging transactions, nor do they include applicable transportation and quality differentials, which are deducted from or added to the index prices on a well by well basis.

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Productive Wells

The following table sets forth the number of active well bores in which we maintain ownership interests as of December 31, 2008:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Louisiana	3	1.6	99	43.9	102	45.5
Texas	5	2.6	326	213.3	331	215.9
Michigan and other	1	0.0	6	0.1	7	0.1
Total Productive Wells	9	4.2	431	257.3	440	261.5

(1) Does not include royalty or overriding royalty interests.
(2) Net working interest.

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. A gross well is a well in which we maintain an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by us equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, 50 wells had completions in multiple producing horizons.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2008. Acreage in which our interest is limited to a royalty or overriding royalty interest is excluded from the table.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	31,203	17,642	28,639	16,690	59,842	34,332
Texas	101,489	70,093	40,095	22,727	141,584	92,820
Michigan			1,920	19	1,920	19
Total	132,692	87,735	70,654	39,436	203,346	127,171

Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to the extent that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not such acreage contains proved reserves. As is customary in the oil and gas industry, we can retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the remaining primary term of such a lease. The natural gas and oil leases in which we have an interest are for varying primary terms; however, most of our developed lease acreage is beyond the primary term and is held so long as natural gas or oil is produced.

Lease Expirations

Our undeveloped acreage, including optioned acreage, expires during the next three years at the rate of 13,600 net acres in 2009, 10,200 net acres in 2010, and 10,800 net acres in 2011, unless included in producing units or extended prior to lease expiration.

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Operator Activities

We operate a majority of our producing properties by value, and will generally seek to become the operator of record on properties we drill or acquire in the future. Chesapeake will operate under our joint development agreement and drill Haynesville Shale wells on our jointly-owned North Louisiana acreage.

Drilling Activities

The following table sets forth our drilling activities for the last three years. As denoted in the following table, gross wells refer to wells in which a working interest is owned, while a net well is deemed to exist when the sum of the fractional working interests we own in gross wells equals one.

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	107	65.9	90	72.0	99	75.9
Non-Productive	2	1.1	1	0.7	1	1.0
Total	109	67.0	91	72.7	100	76.9
Exploratory Wells:						
Productive	17	8.4	5	3.4	4	1.6
Non-Productive					1	0.6
Total	17	8.4	5	3.4	5	2.2
Total Wells:						
Productive	124	74.3	95	75.4	103	77.5
Non-Productive	2	1.1	1	0.7	2	1.6
Total	126	75.4	96	76.1	105	79.1

At December 31, 2008, the Company had 25 gross wells that were in the process of being drilled or completed. Those 25 gross wells consisted of approximately 10 gross development wells (5.3 net) and 15 gross exploratory wells (6.0 net).

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Net Production, Unit Prices and Costs

The following table presents certain information with respect to natural gas and oil production attributable to our interests in all of our fields, the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2008.

	2008	2007	2006
Net Production Continuing Operations:			
Natural gas (MMcf)	23,174	15,281	10,500
Oil and condensate (MBbls)	167	118	106
Total (MMcfe)	24,176	15,991	11,135
Average daily production (Mcfe)	66,054	43,811	30,507
Revenue Continuing Operations (in thousands):			
Natural gas	$ 199,057	$ 102,215	$ 67,372
Oil and condensate	16,312	8,476	6,561
Total	$ 215,369	$ 110,691	$ 73,933
Average Realized Sales Price Per Unit From Continuing Operations:			
Natural gas (per Mcf)	$ 8.59	$ 6.69	$ 6.42
Oil and condensate (per Bbl)	$ 97.70	$ 71.83	$ 62.03
Total (per Mcfe)	$ 8.91	$ 6.92	$ 6.64
Other Data From Continuing Operations (per Mcfe):			
Lease operating	$ 1.32	$ 1.40	$ 1.14
Production and other taxes	$ 0.31	$ 0.14	$ 0.30
Transportation	$ 0.36	$ 0.37	$ 0.34
Depreciation, depletion and amortization	$ 4.43	$ 4.99	$ 3.34
Exploration	$ 0.35	$ 0.46	$ 0.53
Impairment of oil and gas properties	$ 1.18	$ 0.48	$ 0.89
General and administrative	$ 1.00	$ 1.31	$ 1.55

For a discussion of comparative changes in our production volumes, revenues and operating expenses for the three years ended December 31, 2008, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operations .

Oil and Gas Marketing and Major Customers

Marketing. Essentially all of our natural gas production is sold under spot or market-sensitive contracts to various gas purchasers on short-term contracts. Our condensate and crude oil production is sold to various purchasers under short-term rollover agreements based on current market prices.

Customers. 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 these sources as a percent of oil and gas revenues for the year ended December 31, 2008 was as follows:

	2008
Shell Energy	33%
Louis Dreyfus Corporation	20%
Crosstex Energy	9%

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Competition

The oil and gas industry is highly competitive. Major and independent oil and gas companies, drilling and production acquisition programs and individual producers and operators are active bidders for desirable oil and gas properties, as well as the equipment and labor required to operate those properties. Many competitors have financial resources substantially greater than ours, and staffs and facilities substantially larger than us. The availability of a ready market for our oil and gas production will depend in part on the cost and availability of alternative fuels, the level of consumer demand, the extent of domestic production of oil and gas, the extent of importation of foreign oil and gas, the cost of and proximity to pipelines and other transportation facilities, regulations by state and federal authorities and the cost of complying with applicable environmental regulations.

Employees

At February 25, 2009, we had 116 full-time employees in our two administrative offices and one field office, none of whom is represented by any labor union. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection and well testing.

Available Information

Our website address is *http://www.goodrichpetroleum.com.* We make available, free of charge through the Investor Relations portion of this website, annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the 1934 Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports of beneficial ownership filed pursuant to Section 16(a) of the 1934 Act are also available on our website. Information contained on our website is not part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at *http://www.sec.gov*.

Regulations

The availability of a ready market for any natural gas and oil production depends upon numerous factors beyond our control. These factors include regulation of natural gas and oil production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of natural gas and oil available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be shut-in because of an oversupply of natural gas or the lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount of natural gas and oil produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies as well.

Environmental Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Compliance

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with these laws and regulations may require the acquisition of various permits before drilling commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and require remedial measures to mitigate pollution from former and ongoing operations. Failure to comply with these laws and regulations may result in the issuance of administrative, civil and criminal penalties, the assessment of remedial obligations, and the imposition of injunctions that may limit or prohibit some or all of our operations.

The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business. While we believe that we are in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations or financial condition, there is no assurance that this trend will continue in the future.

The following is a summary of the more significant existing environmental laws to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (CERCLA), also known as the Superfund law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or the sites where the release occurred, and those that disposed or arranged for the disposal of hazardous substances released at the site. Under CERCLA, these persons may be subject to joint and several strict liabilities for remediation costs at the site, natural resource damages and for the costs of certain health studies. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We generate materials in the course of our operations that are regulated as hazardous substances. We also may incur liability under the Resource Conservation and Recovery Act, as amended (RCRA), and comparable state statutes which impose requirements related to the handling and disposal of solid and hazardous wastes. The U.S. Environmental Protection Agency (EPA) and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for certain materials generated in the exploration, development or production of oil and gas, we generate petroleum product wastes and ordinary industrial wastes that may be regulated as solid and hazardous wastes.

We currently own or lease, and in the past have owned or leased, properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

The Federal Water Pollution Control Act, as amended, (Clean Water Act), and analogous state law, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal

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and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In addition, the Oil Pollution Act of 1990 (OPA) imposes a variety of requirements related to the prevention of oil spills into navigable waters. OPA subjects owners of facilities to strict, joint and several liabilities for specified oil removal costs and certain other damages including natural reservoir damages arising from a spill. We believe our operations are in substantial compliance with the Clean Water Act and OPA requirements.

The Federal Clean Air Act, as amended, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe our operations are in substantial compliance with applicable air permitting and control technology requirements.

Recent scientific studies have suggested that emissions of certain gases commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth s atmosphere. In response to such studies, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations.

Also, as a result of the United States Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases, including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an Advance Notice of proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court s decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional, or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance or operating costs or additional operating restrictions, any of which could have a material adverse effect on our business or demand for the oil and gas we produce.

State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. In addition, there are state statutes, rules and regulations governing conservation matters, including the unitization or pooling of oil and gas properties, establishment of maximum rates of production from oil and gas wells and the spacing, plugging and abandonment of such wells. Such statutes and regulations may limit the rate at which oil and gas could otherwise be produced from our properties and may restrict the number of wells that may be drilled on a particular lease or in a particular field.

Management believes that we are in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations or financial condition.

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Item 1A. ***Risk Factors***

Our financial and operating results are subject to a number of factors, many of which are not within our control.

The following summarizes some, but not all, of the risks and uncertainties which may adversely affect our business, financial condition or results of operations.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

The proved oil and gas reserve information included in this report are estimates. These estimates are based on reports prepared by NSA, our independent reserve engineers, and were calculated using oil and gas prices as of December 31, 2008. These prices will change and may be lower at the time of production than those prices that prevailed at the end of 2008. Reservoir engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and

future oil and gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and gas reserves attributable to our properties. As required by the SEC, the standardized measure of discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

the amount and timing of actual production;

supply and demand for oil and gas;

increases or decreases in consumption; and

changes in governmental regulations or taxation.

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our PV-10, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

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Our future revenues are dependent on the ability to successfully complete drilling activity.

Drilling and exploration are the main methods we utilize to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- lack of acceptable prospective acreage;
- inadequate capital resources;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- title problems;
- compliance with governmental regulations;
- mechanical difficulties; and
- risks associated with horizontal drilling.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain.

In addition, we recently completed drilling our sixth horizontal well in the Cotton Valley trend. We have only limited experience drilling horizontal wells and there can be no assurance that this method of drilling will be as effective as we currently expect it to be.

In addition, while lower oil and gas prices may reduce the amount of oil and natural gas that we can produce economically, higher oil and gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increasing costs for, such drilling equipment, services and personnel. Such shortages could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues.

Natural gas and oil prices are volatile; a sustained decrease in the price of natural gas or oil would adversely impact our business.

Our success will depend on the market prices of oil and natural gas. These market prices tend to fluctuate significantly in response to factors beyond our control. The prices we receive for our crude oil production are based on global market conditions. The general pace of global economic growth, the continued instability in the Middle East and other oil and gas producing regions and actions of the Organization of Petroleum Exporting Countries, or OPEC, and its maintenance of production constraints, as well as other economic, political, and environmental factors will continue to affect world supply and prices. Domestic natural gas prices fluctuate significantly in response to numerous factors including U.S. economic conditions, weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

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Crude oil and natural gas prices are extremely volatile. Average oil and natural gas prices decreased substantially during the year ended December 31, 2008. Any additional actual or anticipated reduction in crude oil and natural gas prices may further depress the level of exploration, drilling and production activity. We expect that commodity prices will continue to fluctuate significantly in the future. The following table includes high and low natural gas prices (price per Mmbtu) and crude oil prices (West Texas Intermediate or WTI) for 2008, as well as these prices at year-end and at February 25, 2009:

	Henry Hub Per Mmbtu
July 2, 2008 (high)	$ 13.31
December 23, 2008 (low)	5.38
December 31, 2008	5.63
February 25, 2009	4.21

	WTI Per barrel
July 3, 2008 (high)	$ 145.31
December 23, 2008 (low)	30.28
December 31, 2008	44.60
February 25, 2009	41.70

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Prices for natural gas and crude oil declined sharply in the second half of 2008 and have remained low when compared with average prices in recent years. These lower prices, coupled with the recent turmoil in financial markets that has significantly limited and increased the cost of capital, have compelled most natural gas and oil producers, including us, to reduce the level of exploration, drilling and production activity. This will have a significant effect on our capital resources, liquidity and expected operating results. Any sustained reductions in natural gas and oil prices will directly affect our revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Further reductions in oil and natural gas prices could also reduce the quantities of reserves that are commercially recoverable. A reduction in our reserves could have other adverse consequences including a possible downward redetermination of the availability of borrowings under our senior credit facility, which would restrict our liquidity. Additionally, further or continued declines in prices could result in non-cash charges to earnings due to impairment writedowns. Any such writedown could have a material adverse effect on our results of operations in the period taken.

Recent changes in the financial and credit markets may impact economic growth, and a sustained depression of oil and natural gas prices can also affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our current credit facility. This may hinder or prevent us from meeting our future capital needs.

We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on more expensive or otherwise unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Our use of oil and gas price hedging contracts may limit future revenues from price increases and result in significant fluctuations in our net income.

We use hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions

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limits the downside risk of price declines, their use may also limit future revenues from price increases. We hedged approximately 51% of our total production volumes for the year ended December 31, 2008.

Our results of operations may be negatively impacted by our commodity derivative instruments and fixed price forward sales contracts in the future and these instruments may limit any benefit we would receive from increases in the prices for oil and natural gas. For the years ended December 31, 2008 and 2006 we realized a loss on settled commodity derivatives of $1.8 million and $2.1 million, respectively. For the year ended December 31, 2007, we realized a gain on settled commodity derivatives of $9.7 million.

For the year ended December 31, 2008, we recognized in earnings an unrealized gain on commodity derivative instruments not designated as hedges of $55.4 million. For financial reporting purposes, this unrealized gain was combined with a $1.8 million realized loss in 2008 resulting in a total unrealized and realized gain on commodity derivative instruments not designated as hedges of $53.6 million for 2008.

For the year ended December 31, 2007, we recognized in earnings an unrealized loss on commodity derivative instruments not designated as hedges of $16.1 million. For financial reporting purposes, this unrealized loss was combined with a $9.7 million realized gain in 2007 resulting in a total unrealized and realized loss on commodity derivative instruments not designated as hedges of $6.4 million for 2007.

For the year ended December 31, 2006, we recognized in earnings an unrealized gain on commodity derivative instruments not designated as hedges of $40.2 million. For financial reporting purposes, this unrealized gain was combined with a $2.1 million realized loss in 2006 resulting in a total unrealized and realized gain on commodity derivative instruments not designated as hedges of $38.1 million for 2006. This gain was recognized because the natural gas hedges were deemed ineffective for 2006, and all previously effective oil hedges were deemed ineffective for the fourth quarter of 2006.

We account for our commodity derivative contracts in accordance with SFAS 133. SFAS 133 requires each derivative to be recorded on the balance sheet as an asset or liability at its fair value. Additionally, the statement requires that changes in a derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is executed. We have elected not to apply hedge accounting treatment to our swaps and collars and, as such, all changes in the fair value of these instruments are recognized in earnings. Our fixed price physical contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment.

In the future, we will be exposed to volatility in earnings resulting from changes in the fair value of our hedges. See Note 8 Derivative Activities to our consolidated financial statements for further discussion.

Delays in development or production curtailment affecting our material properties may adversely affect our financial position and results of operations.

The size of our operations and our capital expenditure budget limits the number of wells that we can develop in any given year. Complications in the development of any single material well may result in a material adverse affect on our financial condition and results of operations. In addition, a relatively small number of wells contribute a substantial portion of our production. If we were to experience operational problems resulting in the curtailment of production in any of these wells, our total production levels would be adversely affected, which would have a material adverse affect on our financial condition and results of operations.

Because our operations require significant capital expenditures, we may not have the funds available to replace reserves, maintain production or maintain interests in our properties.

We must make a substantial amount of capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. Historically, we have paid for these expenditures with cash from operating activities, proceeds from debt and equity financings and asset sales. Our revenues or cash flows could be reduced because of lower oil and natural gas prices or for other reasons. If our revenues or cash flows decrease, we may not have the funds available to replace reserves or maintain production at current levels. If this occurs, our production will decline over time. Other sources of financing may not be available to us if our cash flows from operations are not sufficient to fund our capital expenditure requirements. Where we are not the majority owner or operator of an oil and gas property, we may have no control over the timing or amount of capital expenditures associated with the particular property. If we cannot fund such capital expenditures, our interests in some properties may be reduced or forfeited.

If we are unable to replace reserves, we may not be able to sustain production at present levels.

Our future success depends largely upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves will decline over time. In addition, approximately 62% of our total estimated proved reserves by volume at December 31, 2008, were undeveloped. By their nature, estimates of undeveloped reserves and timing of their production are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. The lack of availability of sufficient capital to fund such future operations could materially hinder or delay our replacement of produced reserves. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

We may incur substantial impairment writedowns.

If management s estimates of the recoverable reserves on a property are revised downward or if oil and natural gas prices decline, we may be required to record additional non-cash impairment writedowns in the future, which would result in a negative impact to our financial position. Furthermore, any sustained decline in oil and natural gas prices may require us to make further impairments. We review our proved oil and gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management s estimates of future oil and natural gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units estimated reserves, future cash flows and fair value. For the years ended December 31, 2008, 2007 and 2006, we recorded impairments from continuing operations related to oil and gas properties of $28.6 million, $7.7 million and $9.9 million, respectively.

Management s assumptions used in calculating oil and gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property s fair value. Additionally, as management s views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

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A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Approximately 99% of our estimated proved reserves at December 31, 2008, and a similar percentage of our production during 2008 were associated with our Cotton Valley trend properties. Accordingly, if the level of production from these properties substantially declines or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention or natural disasters, it could have a material adverse effect on our overall production level and our revenue.

The results of our planned exploratory horizontal drilling in the Haynesville Shale, a newly emerging play with limited drilling and production history, are subject to more uncertainties than our drilling program in the more established shallower Cotton Valley formation and may not meet our expectations for reserves or production.

We have only recently participated in the drilling of our first four horizontal wells drilled in the Haynesville Shale. Production history from horizontal wells in the Haynesville Shale is limited due to the initial discovery occurring within the last 18 months. Part of the drilling strategy to maximize recoveries from the drilling of horizontal wells in the Haynesville Shale is to use completion techniques involving extensive pressure stimulation and fracturing that have proven successful in other shale formations. The ultimate success of our horizontal drilling and completion strategy and techniques in the formation will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, the ultimate results of our future horizontal drilling in the Haynesville Shale over our acreage position are more uncertain than drilling results in the shallower Cotton Valley, where we have established reserves and production as a result of years of development.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. For example, Chesapeake and Matador Resources Company operate certain properties in the Haynesville Shale. Encana Corporation and St. Mary Land and Exploration Company operate certain properties in the Cotton Valley trend. We have less ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them versus those fields in which we are the operator. Our dependence on the operator and other working interest owners for these projects and our reduced influence or ability to control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

Our ability to sell natural gas and receive market prices for our gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

We operate primarily in the Cotton Valley trend, which is in the same geographic region as the recently discovered Haynesville Shale. A number of companies are currently operating in the Haynesville Shale. If drilling in the Haynesville Shale continues to be successful, the amount of natural gas being produced could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in this region. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Cotton Valley trend and Haynesville Shale region may not occur or may be substantially delayed for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas production at significantly lower prices than those quoted on NYMEX or that we currently project, which would adversely affect our results of operations

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A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

Our debt instruments impose restrictions on us that may affect our ability to successfully operate our business.

Our senior credit facility and second lien term loan contain customary restrictions, including covenants limiting our ability to incur additional debt, grant liens, make investments, consolidate, merge or acquire other businesses, sell assets, pay dividends and other distributions and enter into transactions with affiliates. We also are required to meet specified financial ratios under the terms of our senior credit facility and second lien term loan. As of December 31, 2008, we were in compliance with all the financial covenants of our senior credit facility and our second lien term loan. These restrictions may make it difficult for us to successfully execute our business strategy or to compete in our industry with companies not similarly restricted. In addition, our current senior credit facility matures in February, 2010. Any replacement credit facility may have more restrictive covenants or provide us with less borrowing capacity.

We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

The acquisition of properties requires us to assess a number of factors, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, platform or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities relating to the acquired assets and indemnities are unlikely to cover liabilities relating to the time periods after closing. We may be required to assume any risk relating to the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. The incurrence of an unexpected liability could have a material adverse effect on our financial position and results of operations.

We are subject to complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Development, production and sale of natural gas and oil in the U.S. are subject to extensive laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- bonds for ownership, development and production of oil and gas properties;

- reports concerning operations; and

- taxation.

In addition, our operations are subject to stringent federal, state and local environmental laws and regulations governing the discharge of materials into the environment and environmental protection. Governmental authorities enforce compliance with these laws and regulations and the permits issued under them, which can result in an obligation to undertake difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the

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imposition of remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of our operations. There is inherent risk of incurring significant environmental costs and liabilities in our business. The imposition of joint and several and strict liabilities is common in environmental laws and may result in us incurring costs in connection with discharges or releases of hydrocarbons and wastes due to our handling of hydrocarbons and wastes, the release of air emissions or water discharges in connection with our operations, and historical industry operations and waste disposal practices conducted by us or predecessor operators on, under or from our properties and from facilities where our wastes have been taken for disposal. Private parties affected by such discharges or releases may also have the right to pursue legal actions to enforce compliance as well as seek damages for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly requirements could have a material adverse effect on our business.

Competition in the oil and gas industry is intense, and we are smaller and have a more limited operating history than some of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop these properties. Some of our competitors have substantially greater financial and other resources than us. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for oil and natural gas properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. Our ability to acquire additional properties and develop new and existing properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Our success depends on our management team and other key personnel, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

Terrorist attacks or similar hostilities may adversely impact our results of operations.

The impact that future terrorist attacks or regional hostilities (particularly in the Middle East) may have on the energy industry in general, and on us in particular, is unknown. Uncertainty surrounding military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. Moreover, we have incurred additional costs since the terrorist attacks of September 11, 2001 to safeguard certain of our assets and we may be required to incur significant additional costs in the future.

The terrorist attacks on September 11, 2001, and the changes in the insurance markets attributable to such attacks have made certain types of insurance more difficult for us to obtain. There can be no assurance that insurance will be available to us without significant additional costs. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

The oil and gas business involves many uncertainties, economic risks and operating risks that can prevent us from realizing profits and can cause substantial losses.

The nature of the oil and gas business involves certain operating hazards such as well blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, formations with abnormal pressures, pollution,

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releases of toxic gas and other environmental hazards and risks. Any of these operating hazards could result in substantial losses to us. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of our properties. Additionally, some of our oil and gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. In accordance with customary industry practices, we maintain insurance against some, but not all, of such risks and losses. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Our large inventory of undeveloped acreage and large percentage of undeveloped proved reserves may create additional economic risk.

Our success is largely dependent upon our ability to develop our large inventory of future drilling locations, undeveloped acreage and undeveloped reserves in our resource-style plays in Texas and Louisiana. As of December 31, 2008 approximately 62% of our total proved reserves were undeveloped. To the extent our drilling results are not as successful as we anticipate, natural gas and oil prices decline, or sufficient funds are not

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available to drill these locations and reserves, we may not capture the expected or projected value of these properties. In addition, our estimates of gross unrisked well locations included in this report may not be reflective of what we will, or could, drill on such acreage. Such estimates are intended only to reflect our current view of the potential for drilling on such acreage. The numbers of wells on such acreage that we drill or participate in drilling could be substantially different.

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

We are party to 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.

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

None.

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PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market Price of Our Common Stock

Our common stock is traded on the New York Stock Exchange under the symbol GDP .

At February 25, 2009, the number of holders of record of our common stock without determination of the number of individual participants in security positions was 1,397 with 37,631,407 shares outstanding. High and low sales prices for our common stock for each quarter during the calendar years 2008 and 2007 are as follows:

	2008		2007	
	High	**Low**	**High**	**Low**
First Quarter	$ 30.08	$ 18.32	$ 36.90	$ 28.09
Second Quarter	82.92	29.02	38.31	30.91
Third Quarter	80.49	37.05	41.14	28.64
Fourth Quarter	41.84	20.48	35.20	22.05

Dividends

We have neither declared nor paid any cash dividends on our common stock and do not anticipate declaring any dividends in the foreseeable future. We expect to retain our cash for the operation and expansion of our business, including exploration, development and production activities. In addition, our senior bank credit facility contains restrictions on the payment of dividends to the holders of common stock. For additional information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Issuer Repurchases of Equity Securities

We made no open market repurchases of our common stock for the year ended December 31, 2008. When an employee s restricted stock shares vest, the company (at the option of the employee) generally withholds an amount of shares necessary to cover that employees minimum income tax withholding obligation. The company then advances the withholding amount to the appropriate tax authority and subsequently retires the shares. During 2008, we withheld 15,640 shares in this manner and paid $0.5 million to the appropriate tax authority as minimum withholding.

For information on securities authorized for issuance under our equity compensation plans, see Item 12. Security Ownership of Certain Beneficial Owners and Management.

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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. 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,				
	2008	2007	2006	2005	2004
	(In thousands, except per share amounts)				
Revenues:					
Oil and gas revenues	$ 215,369	$ 110,691	$ 73,933	$ 34,986	$ 3,759
Other	682	614	838	325	151
	216,051	111,305	74,771	35,311	3,910
Operating Expenses					
Lease operating expense	31,950	22,465	12,688	3,494	306
Production and other taxes	7,542	2,272	3,345	2,136	205
Transportation	8,645	5,964	3,791	558	
Depreciation, depletion and amortization	107,123	79,766	37,225	12,214	1,486
Exploration	8,404	7,346	5,888	5,697	955
Impairment of oil and gas properties	28,582	7,696	9,886	340	
General and administrative	24,254	20,888	17,223	8,622	5,821
Gain on sale of assets	(145,876)	(42)	(23)	(235)	(50)
Other		109			
	70,624	146,464	90,023	32,826	8,723
Operating income (loss)	145,427	(35,159)	(15,252)	2,485	(4,813)
Other income (expense):					
Interest expense	(15,862)	(11,870)	(7,845)	(2,359)	(1,110)
Interest Income	2,184				
Gain (loss) on derivatives not designated as hedges	51,547	(6,439)	38,128	(37,680)	2,317
Loss on early extinguishment of debt			(612)		
	37,869	(18,309)	29,671	(40,039)	1,207
Income (loss) from continuing operations before income taxes	183,296	(53,468)	14,419	(37,554)	(3,606)
Income tax (expense) benefit	(46,556)	(3,034)	(5,120)	13,144	8,594
Income (loss) from continuing operations	136,740	(56,502)	9,299	(24,410)	4,988
Discontinued operations including gain on sale of assets, net of income taxes	(502)	11,469	(7,660)	6,960	13,539
Net income (loss)	136,238	(45,033)	1,639	(17,450)	18,527
Preferred stock dividends	6,047	6,047	6,016	755	633

Preferred stock redemption premium			1,545		
Net income (loss) applicable to common stock	$ 130,191	$ (51,080)	$ (5,922)	$ (18,205)	$ 17,894
Income (loss) per common share from continuing operations:					
Basic	$ 4.04	$ (2.21)	$ 0.37	$ (1.05)	$ 0.26
Diluted	$ 3.49	$ (2.21)	$ 0.37	$ (1.05)	$ 0.25
Income (loss) per common share from discontinued operations:					
Basic	$ (0.01)	$ 0.45	$ (0.30)	$ 0.30	$ 0.69
Diluted	$ (0.01)	$ 0.45	$ (0.31)	$ 0.30	$ 0.66
Weighted average number of common shares outstanding:					
Basic	33,806	25,578	24,948	23,333	19,552
Diluted	40,397	25,578	25,412	23,333	20,347

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	Year Ended December 31,				
	2008	2007	2006	2005	2004
			(In thousands)		
Balance Sheet Data:					
Total assets	$ 1,038,946	$ 590,118	$ 479,264	$ 296,526	$ 127,977
Total long-term debt	250,000	215,500	201,500	30,000	27,000
Stockholders equity	650,646	283,615	205,133	181,589	65,307

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 our 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 our 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 and availability of capital.

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 adversely affect our 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, including the recently discovered Haynesville Shale play in the same general area. 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

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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 because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains and losses.

Our revenues and operating cash flow are dependent on the successful development of our inventory of capital projects with available capital, 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

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 and Caddo Parishes, Louisiana. We continue to build our acreage position in the Cotton Valley trend and hold 201,203 gross acres as of December 31, 2008. As of year end 2008, we drilled and completed a cumulative total of 414 Cotton Valley trend wells with a success rate in excess of 98%. Our net production volumes from our Cotton Valley trend wells aggregated approximately 65,598 Mcfe per day in 2008, or approximately 99% of our total oil and gas production for the year.

2008 Haynesville Shale Transactions

Chesapeake Haynesville Joint Development

On June 16, 2008, we entered into a joint development agreement with Chesapeake Energy Corporation, or Chesapeake, to develop our Haynesville Shale acreage in the Bethany Longstreet and Longwood fields of Caddo and DeSoto Parishes, Louisiana. Chesapeake purchased the deep rights, including the Haynesville Shale, to approximately 10,250 net acres of oil and natural gas leasehold comprised of a 20% working interest in approximately 25,000 net acres in the Bethany Longstreet field and a 50% working interest in approximately 10,500 net acres in the Longwood field for net proceeds of $172.0 million. Chesapeake also purchased 7,500 net acres of deep rights in the Bethany Longstreet field from a third party (see Note 11 Related Party Transactions to our consolidated financial statements), bringing the ownership interest in the deep rights in both fields after closing to 50% each for us and Chesapeake. Chesapeake is the operator of the joint Haynesville Shale development. As a result of this transaction, we hold approximately 25,000 gross (12,500 net) acres in the deep rights in the Bethany Longstreet field and approximately 10,500 gross (5,250 net) acres in the deep rights in the Longwood field, both of which are currently believed to be prospective for the Haynesville Shale. Through our joint development arrangement with Chesapeake, we will continue to operate existing production and operate any new wells drilled to the base of the Cotton Valley sand, and Chesapeake will operate any wells drilled below the base of the Cotton Valley sand, including the Haynesville Shale.

We retained the shallow rights to the base of the Cotton Valley sand and the existing production and reserves with respect to our 70% working interest in the Bethany Longstreet field and our 100% working interest in the Longwood field. We also retained our interest in both the shallow and Haynesville Shale rights on all of our East Texas assets. During the third quarter of 2008, Chesapeake began drilling the Holland 17H No.1 as the first horizontal well on the joint acreage in Bethany Longstreet field. In the Longwood field, Chesapeake re-entered the Lona Johnson No.1 drilling it to the deeper Haynesville Shale as a horizontal well and recovered

154 feet of core from the formation to evaluate. During the fourth quarter of 2008, completion operations began on both of these wells and two horizontal Haynesville Shale development wells were spud in Bethany Longstreet field together with two Haynesville Shale wells in Longwood field. In 2009, we and Chesapeake plan to use approximately three rigs most of the year to drill 22 gross joint wells.

Caddo Parish Acquisition

On May 28, 2008, we acquired additional interests in the Cotton Valley trend, increasing our net exposure in the Haynesville Shale. We acquired approximately 3,665 net acres in Longwood field of Caddo Parish, Louisiana, through the issuance of 908,098 shares of our common stock valued at approximately $33.9 million. The purchase included interests in 25 gross wells, with approximately 1.1 Mmcfe per day of net production, and 5.2 Bcfe of proved reserves (77% developed) associated with the shallower Hosston and Cotton Valley formations. As of December 31, 2008, we had drilled and participated in three Haynesville wells.

Caddo Pine Island Acquisition

On June 10, 2008, we entered into a definitive agreement with a private company for the right to acquire over time a 50% non-operated interest in 5,800 gross (2,900 net) acres in the Caddo Pine Island field, north of and adjacent to our Longwood field in Caddo Parish, Louisiana. Total consideration paid was approximately $3.3 million, which was comprised of acreage costs for the 50% interest in the leasehold and the cost of a carried interest on the initial well drilled on the acreage. As of December 31, 2008, four wells had been drilled vertically to the Haynesville Shale on this acreage. In the fourth quarter of 2008, we re-entered two of these wells to drill them horizontally in the Haynesville Shale formation. Completion of the first horizontal well will start in the first quarter of 2009 and we expect to complete the other wells in the second quarter of 2009. In 2009, we plan to drill two additional horizontal Haynesville Shale wells on the acreage.

In connection with the Chesapeake joint development agreement, the Caddo Parish Acquisition and the Caddo Pine Island Acquisition, we have a total of approximately 22,000 net acres in North Louisiana which we believe to be prospective for the Haynesville Shale formation.

Initial Company Operated Haynesville Shale Drilling Program

As of December 31, 2008, we have been the operator on and drilled four vertical wells on our North Louisiana acreage and seven wells on our East Texas acreage, for a total of eleven vertical wells targeting the Haynesville Shale. In the fourth quarter of 2008, we began drilling our first operated horizontal Haynesville Shale well. We expect to complete this well in the first quarter of 2009. We expect that our development of the Haynesville Shale will continue in 2009 with the drilling and completion of nine company operated horizontal wells in East Texas.

Sale of South Louisiana Assets

On March 20, 2007, we completed the sale of substantially all of our assets in South Louisiana to a private company. The sale resulted in total proceeds of $72.3 million, net to us, after normal closing adjustments. We recognized a gain of $9.7 million (net of tax) in 2007. The effective date of the sale was July 1, 2006.

On August 4, 2008, we closed the sale of the St. Gabriel field to a private party for $0.1 million, resulting in a gain of $0.1 million. On August 12, 2008, we assigned our rights in the Bayou Bouillon field to a private party for a nominal amount. We realized a loss of $0.3 million. We continue to hold our interests in the Plumb Bob field. We have an asset retirement obligation of $1.4 million on the balance sheet for properties in the Plumb Bob field.

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Overview of 2008 Results

We achieved annual production volume growth of 51% with production growing from 16.0 Bcfe in 2007 to 24.2 Bcfe in 2008.

We entered into an agreement with Chesapeake to jointly develop a portion of our Haynesville Shale acreage in Northwest Louisiana. We sold a portion of our interest in the Haynesville Shale deep rights at the Bethany Longstreet and Longwood fields to Chesapeake for net proceeds of $172.0 million resulting in a gain of $145.1 million. Chesapeake serves as operator for these properties.

We established our presence in the Haynesville Shale play in Northwest Louisiana and East Texas and increased our ownership to approximately 63,000 net acres at December 31, 2008.

We drilled and completed 126 gross (75.4 net) wells in 2008, as compared to 104 gross (64.65 net) wells in 2007.

We raised net proceeds of $191.3 million from our equity offering in July 2008 and paid down all of the outstanding borrowings under our senior credit facility. We ended the year with $147.5 million in cash and short term investments.

Estimated proved reserves grew 12% to approximately 402.3 Bcfe (approximately 390.4 Bcf of natural gas and 1.9 MMBbls of oil and condensate), with a PV-10 of $169.8 million (before discounted future income taxes of $2.4 million) and a standardized measure of $167.4 million, approximately 38% of which is developed.

Capital expenditures totaled $380.1 million in 2008, versus $300.1 million in 2007.

Our 2008 oil and gas revenues from continuing operations totaled $215.4 million compared to $110.7 million in 2007, a 95% increase.

Net cash provided by operating activities increased $21.1 million from 2007, to $107.0 million in 2008.

We reduced our total operating expenses by $0.90 per Mcfe from 2007 to 2008 excluding impairment expense and the impact of the $145.9 million gain on sale of assets during the third quarter of 2008 in making these calculations.

Summary Operating Information:	**Year End December 31,**				**Year End December 31,**			
Continuing Operations	**2008**	**2007**	**Variance**		**2007**	**2006**	**Variance**	
	(In thousands, except for price data)							
Revenues:								
Natural gas	$ 199,057	$ 102,215	$ 96,842	95%	$ 102,215	$ 67,372	$ 34,843	52%
Oil and condensate	16,312	8,476	7,836	92%	8,476	6,561	1,915	29%
Natural gas, oil and condensate	215,369	110,691	104,678	95%	110,691	73,933	36,758	50%
Operating revenues	216,051	111,305	104,746	94%	111,305	74,771	36,534	49%
Operating expenses	70,624	146,464	(75,840)	(52%)	146,464	90,023	56,441	63%
Operating income (loss)	145,427	(35,159)	180,586	514%	(35,159)	(15,252)	(19,907)	(131%)
Net income (loss) applicable to common stock	130,191	(51,080)	181,271	355%	(51,080)	(5,922)	(45,158)	(763%)

Net Production:								
Natural gas (MMcf)	23,174	15,281	7,893	52%	15,281	10,500	4,781	46%
Oil and condensate (MBbls)	167	118	49	42%	118	106	12	11%
Total (MMcfe)	24,176	15,991	8,185	51%	15,991	11,135	4,856	44%
Average daily production (Mcfe/d)	66,054	43,811	22,243	51%	43,811	30,507	13,304	44%
Average Realized Sales Price Per Unit:								
Natural gas (per Mcf)	$ 8.59	$ 6.69	$ 1.90	28%	$ 6.69	$ 6.42	$ 0.27	4%
Oil and condensate (per Bbl)	97.70	71.83	25.87	36%	71.83	62.03	9.80	16%
Average realized price (per Mcfe)	8.91	6.92	1.99	29%	6.92	6.64	0.28	4%

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Results of Operations

For the year ended December 31, 2008, we reported net income applicable to common stock of $130.2 million, or $3.85 per share (basic) and $3.48 per share (diluted), on oil and gas revenues from continuing operations of $215.4 million. This compares to a net loss applicable to common stock of $51.1 million, or $2.00 per share (basic and diluted) for the year ended December 31, 2007, and a net loss applicable to common stock of $5.9 million, or $0.24 per share (basic and diluted) for the year ended December 31, 2006.

Some highlights for the year ended December 31, 2008 include:

- We recorded a $145.9 million gain on the sale of assets in a sale that closed in July 2008. This gain includes $145.1 million from the sale of a portion of our interest in the Haynesville Shale deep rights to Chesapeake.

- In conjunction with the decline in natural gas prices during late 2008, we recorded a $51.5 million gain on derivatives not designated as hedges for the year ended December 31, 2008. This includes a realized loss of $1.8 million and an unrealized gain of $55.4 million for our natural gas commodity contracts and a realized loss of $0.7 million and an unrealized loss of $1.4 million on our interest rate swaps.

- Our income tax expense for the year was reduced by a $25.5 million decrease in our valuation allowance related to our deferred tax assets. We released a majority of our valuation allowance in the third quarter of 2008 upon closing and recognizing a significant gain on the Chesapeake sale.

Operating Income

Year ended December 31, 2008 compared to year ended December 31, 2007

Revenues from continuing operations increased 94% compared to 2007, to a total of $216.1 million in 2008 due to a 51% increase in production and a 29% increase in the average realized price. Production increased year-to-year from 15,991 MMcfe to 24,176 MMcfe and our average realized price increased from $6.92 per Mcfe to $8.91 per Mcfe. The drilling and completion of 126 wells in the Cotton Valley trend resulted in the continued natural gas production growth for the company, even though we estimate we curtailed approximately 300 MMcfe of natural gas production in September 2008 as a result of Hurricane Ike. Operating expenses of $70.6 million for the year ended December 31, 2008, include the $145.9 million gain on sale of assets as a reduction in operating expenses and impairment expense of $28.6 million. Excluding the gain on sales of assets for 2008 and impairment expense for both 2008 and 2007, operating expenses of $187.9 million increased 35% or $49.1 million over 2007 operating expenses of $138.8 million (not including $7.7 million of impairment expense). This increase is a direct result of increased production from year-to-year. Although revenues were up significantly for the full year, we experienced a substantial reduction in revenues in the last half of 2008 versus the first half of the year, due to the substantial oil and natural gas price declines.

Year ended December 31, 2007 compared to year ended December 31, 2006

Operating revenues increased 49%, or $36.5 million, compared to 2006, to a total of $111.3 million in 2007 due to production increases and a slight increase in average realized price per Mcfe. Production increased 44% year-to-year from 11,135 MMcfe to 15,991 MMcfe and our average realized price increased 4% from $6.64 Mcfe to $6.92 per Mcfe. The drilling and completion of 95 wells in the Cotton Valley trend led to the gains in natural gas production for 2007. Operating expenses increased 63% to $146.5 million in 2007. The primary driver behind the $56.4 million increase in operating expenses was a $42.5 million increase in depreciation, depletion and amortization (DD&A) year-to-year.

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Operating Expenses (in thousands)	Year Ended December 31, 2008	2007	Variance		Year Ended December 31, 2007	2006	Variance	
Lease operating expenses	$ 31,950	$ 22,465	$ 9,485	42%	$ 22,465	$ 12,688	$ 9,777	77%
Production and other taxes	7,542	2,272	5,270	232%	2,272	3,345	(1,073)	(32%)
Transportation	8,645	5,964	2,681	45%	5,964	3,791	2,173	57%
Depreciation, depletion and amortization	107,123	79,766	27,357	34%	79,766	37,225	42,541	114%
Exploration	8,404	7,346	1,058	14%	7,346	5,888	1,458	25%
Impairment	28,582	7,696	20,886	271%	7,696	9,886	(2,190)	(22%)
General and administrative	24,254	20,888	3,366	16%	20,888	17,223	3,665	21%

Operating Expenses per Mcfe	Year Ended December 31, 2008	2007	Variance		Year Ended December 31, 2007	2006	Variance	
Lease operating expenses	$ 1.32	$ 1.40	$ (0.08)	(6%)	$ 1.40	$ 1.14	$ 0.26	23%
Production and other taxes	0.31	0.14	0.17	121%	0.14	0.30	(0.16)	(53%)
Transportation	0.36	0.37	(0.01)	(3%)	0.37	0.34	0.03	9%
Depreciation, depletion and amortization	4.43	4.99	(0.56)	(11%)	4.99	3.34	1.65	49%
Exploration	0.35	0.46	(0.11)	(24%)	0.46	0.53	(0.07)	(13%)
Impairment of oil and gas properties	1.18	0.48	0.70	146%	0.48	0.89	(0.41)	(46%)
General and administrative	1.00	1.31	(0.31)	(24%)	1.31	1.55	(0.24)	(15%)

Operating Expenses

Year ended December 31, 2008 compared to year ended December 31, 2007

LOE decreased $0.08 per Mcfe, or 6%, on a per unit basis compared to 2007. Production gains of 51% year-over-year offset the impact of generally higher costs. On an absolute dollar basis, LOE increased $9.5 million or 42% for 2008 as compared to 2007. The largest cost components of LOE for 2008 include salt water disposal (SWD) costs of $9.7 million, compressor rental costs of $6.6 million and LOE for properties operated by others (Non-Op) of $2.0 million. SWD and compressor rental costs tend to fluctuate with production. As a result of increased production, SWD increased $3.0 million in 2008 ($9.7 million or $0.40 per Mcfe for 2008 versus $6.7 million or $0.42 per Mcfe for 2007). Compressor rental costs increased $2.1 million in 2008 ($6.6 million or $0.27 per Mcfe for 2008 versus $4.5 million or $0.28 per Mcfe for 2007). Both of these cost areas were relatively flat on a per Mcfe basis. Non-Op LOE also increased $1.1 million ($2.0 million or $0.08 per Mcfe for 2008 versus $0.9 million or $0.06 per Mcfe for 2007) due to a greater number of our properties being operated by others. The remaining $3.3 million increase year-to-year represents the increased cost of labor, services and chemicals partially offset by lower workover costs. Workover costs represented $0.16 per Mcfe of the LOE rate for 2007, while workover costs only represented $0.06 per Mcfe of the LOE rate for 2008, due to fewer workover projects slated for 2008.

Production and other taxes of $7.5 million for 2008 include production tax of $5.5 million and ad valorem tax of $2.0 million. For 2007, production and other taxes of $2.3 million include production tax of $1.1 million and ad valorem tax of $1.2 million. Production tax for 2008 is net of $3.2 million of accrued Tight Gas Sands (TGS) credits for our wells in the State of Texas, which credits equate to $0.13 per Mcfe of production. This compares to TGS credits of $3.9 million for 2007. These TGS credits allow for reduced and in many cases the complete elimination of severance taxes in the State of Texas for qualifying wells for up to ten years of production. We only accrue for such credits once we have been notified of the State s approval. We also anticipate lower production tax rates in the future as we continue to add Cotton Valley trend wells to our production base and as credits are approved. Production taxes are higher for 2008 as the result of a 51% increase in production over 2007, as well as the higher prices received during the year.

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Ad valorem taxes increased to $2.0 million for 2008 from $1.2 million for 2007. Ad valorem tax is assessed on the value of properties as of the first day of the year and is highly influenced by commodity prices for the prior several months. The number of properties we owned increased from January 1, 2007 to January 1, 2008 and the assessed values for our existing properties were higher year-to-year. The combination of these two factors led to the increase in ad valorem taxes year-to-year.

Transportation expense increased 45% to $8.6 million in 2008 compared to $6.0 million in 2007, as a result of a 51% increase in production year-to-year. The rate per Mcfe decreased slightly to $0.36 per Mcfe in 2008 from $0.37 the prior year.

DD&A expense increased to $107.1 million in 2008 from $79.8 million in 2007 due to a 51% increase in production year-to-year. The DD&A rate declined from $4.99 per Mcfe for 2007 to $4.43 per Mcfe for 2008. We calculated the first and second quarter 2008 DD&A rates using the December 31, 2007 reserves. During the third quarter of 2008, we engaged an independent engineering firm to fully engineer our June 30, 2008 proved reserve estimates. The mid-year reserve report was used to calculate the rate for the third and fourth quarters of 2008. The DD&A rate per Mcfe based on this report resulted in a DD&A rate of $4.17 per Mcfe and $4.11 per Mcfe for the third and fourth quarters of 2008, respectively. These rates are lower than the rates used for the first half of 2008 due to the cost effective drilling of wells in the first six months of 2008. We engaged the same firm to prepare a mid-year reserve report in 2007 as well as year-end reports since 2005.

Exploration expense for 2008 increased to $8.4 million from $7.3 million for 2007. The primary component of exploration expense for us is the amortization of undeveloped leasehold costs, which represented $5.8 million of the total. Exploration expenses on a per unit basis declined by 24% from $0.46 per Mcfe for 2007 to $0.35 per Mcfe for 2008. Exploration expenses include $0.3 million for exploratory dry hole costs.

We recorded impairment expense of $28.6 million in 2008, $27.5 million in connection with our independent engineer s report on our reserves as of December 31, 2008. The expense relates to the Brachfield, Blocker, Alabama Bend and Gilmer Fields, which are located in non-core areas in North Louisiana and East Texas. We recorded an impairment expense of $7.7 million in 2007 for our Alabama Bend field and two wells in a non-core area of East Texas.

General and administrative (G&A) expense increased 16% to $24.3 million for 2008 compared to $20.9 million for 2007. G&A on a per unit basis decreased 24% to $1.00 per Mcfe resulting from a 51% increase in production volumes in 2008 as compared to 2007. This increase in costs results from a 33% increase in the number of employees from 86 at December 31, 2007 to 114 at December 31, 2008. Stock based compensation expense, which is a non-cash item, amounted to $5.5 million in 2008 compared to $5.3 million for 2007.

Year ended December 31, 2007 compared to year ended December 31, 2006

LOE for 2007 increased 78% to $22.5 million from $12.7 million for 2006. Generally higher operating costs, primarily SWD and compression costs, contributed to the majority of the increase in 2007. Most of our fields experienced increases in the cost of SWD due to rising fuel costs for trucking. We did see lower SWD costs for the year in the Beckville field, beginning in June 2007, when our East Texas low pressure gathering system (LPGS) in the Beckville field became operational. The LPGS lowers SWD costs by utilizing flowlines to pipe the water to the commercial SWD wells rather than hauling the water with trucks. Higher workover costs also contributed to the higher LOE. Workover costs rose $0.13 per Mcfe with increased activity in the Beckville and North Minden fields ($2.6 million or $0.16 per Mcfe in 2007 vs. $0.3 million or $0.03 per Mcfe in 2006).

Production and other taxes of $2.3 million for 2007 consist of production tax of $1.1 million and ad valorem tax of $1.2 million. Production and ad valorem taxes in 2006 were $2.9 million and $0.4 million, respectively. Production tax in 2007 included $3.9 million of accrued TGS credits for our wells in the State of Texas. Ad valorem tax is assessed on the value of properties as of the first day of the year. The number of properties we

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owned increased from January 1, 2006 to January 1, 2007 and the assessed values for our existing properties were higher year-to-year. The combination of these two factors led to the increase in ad valorem taxes year-to-year.

Transportation expense was $6.0 million in 2007 compared to $3.8 million for 2006 as production volumes increased 44 % year-over-year. The unit cost increased nine percent (from $0.34 per Mcfe in 2006 to $0.37 per Mcfe in 2007) due to an increase in production rates from fields requiring greater transportation, and due to several contracts entered into which transported gas to higher valued markets.

DD&A expense increased to $79.8 million in 2007 from $37.2 million for 2006 primarily due to a higher DD&A rate coupled with higher levels of production. Since we use the successful efforts method of accounting, our DD&A rate is primarily a function of our capitalized drilling, completion and facilities costs divided by our proved developed reserves. Beginning in late 2004/early 2005 we embarked on an aggressive drilling program to fully develop our extensive East Texas/North Louisiana Cotton Valley trend acreage position during a period of record high costs for drilling and completion services. Additionally, to hold the majority of our acreage and thereby allow for the most prudent development plan going forward, we chose to drill many wells in the outlying areas of our acreage block, where per well results were less certain than in the initial established areas. Finally, many of our initial wells in certain fields required us to pay the costs of other industry partners to earn access to the full acreage position.

We calculated first and second quarter 2007 DD&A rates using the December 31, 2006 reserves, which did not recognize any impact of our 2007 Cotton Valley trend drilling program reserve additions. During 2007, we engaged NSA, our independent reserve engineers, to fully engineer our June 30, 2007 proved reserve estimates. This mid-year reserve report was used to calculate rates for the third and fourth quarters of 2007. As mentioned above, the DD&A rate per Mcfe based on this report was $4.77, which was lower than the rate used for the first half of this year primarily due to the inclusion of more wells drilled in our core areas during the first half of this year relative to the mix of wells in the December 31, 2006 reserve report.

Exploration expenses for 2007 increased to $7.3 million from $5.9 million for 2006. Exploration expenses on a per unit basis declined to $0.46 per Mcfe in 2007 from $0.53 per Mcfe in 2006. The increase in exploration expense year-to-year relates to an increase in leasehold amortization, a non-cash expense and the largest component of exploration expense. We increased our undeveloped acreage position from last year which resulted in higher leasehold cost amortization of $6.1 million for 2007, compared to $4.8 million in the same period last year.

We recorded an impairment expense of $7.7 million for the year ended December 31, 2007, $6.1 million of which related to our Alabama Bend field located in the other Cotton Valley trend leasehold area. We also recorded an impairment expense of $1.4 million and $0.3 million in the fourth and third quarters of 2007, respectively, related to two wells in a non-core area of East Texas. We recorded impairment expense in conjunction with the receipt of the independent engineer s year-end and mid-year reports on reserves.

G&A expense increased to $20.9 million for 2007, compared to $17.2 million for 2006, resulting from generally higher compensation costs and a Louisiana franchise tax payment made under protest. G&A on a per unit basis decreased 17% as a result of higher production volumes in 2007. Salaries and benefits account for a large portion of total G&A. After the sale of substantially all of our properties in South Louisiana in March 2007, we had 74 employees. As of December 31, 2007, we had 86 employees. We paid $0.3 million in severance to employees in conjunction with the sale of all of our South Louisiana properties in March 2007. G&A for the year also includes a $0.3 million non-cash charge for the acceleration of vesting of options and restricted stock associated with the resignation of an officer of the Company effective August 30, 2007.

We accrued a liability for $1.0 million in March 2007, representing $0.4 million in penalties and interest and $0.6 million the State of Louisiana asserts we owe for franchise taxes (see Note 9 Discontinued Operations to

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our consolidated financial statements). While we paid this amount under protest in April 2007, we plan to pursue the reimbursement of the full $1.0 million. Should our efforts prevail, the amounts paid under protest would be refunded.

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Other Income (Expense):			
Interest expense	$ (15,862)	$ (11,870)	$ (7,845)
Interest Income	2,184		
Gain (loss) on derivatives not designated as hedges	51,547	(6,439)	38,128
Loss on early extinguishment of debt			(612)
Income tax expense	(46,556)	(3,034)	(5,120)
Gain on disposal, net of tax	29	9,662	
Income (loss) from discontinued operations, net of tax	(531)	1,807	(7,660)
Average total borrowings	271,246	235,712	99,542
Weighted average interest rate	5.8%	5.0%	7.5%

Other Income (Expense)

Year ended December 31, 2008 compared to December 31, 2007

Interest expense increased by $4.0 million, or 34%, to $15.9 million for 2008 compared to $11.9 million for 2007 as a result of a higher average level of borrowings in 2008, and a slightly higher weighted average interest rate. We added a second lien term loan in January 2008 for $75.0 million, which carries a higher interest rate than both our Senior Credit Facility and our 3.25% convertible senior notes. In July 2008, we paid off all amounts outstanding under our Senior Credit Facility with the proceeds from the sale of assets and an equity offering. We ended the year with no amounts outstanding under our Senior Credit Facility.

We invested the net proceeds from our equity offering and the sale of assets, both in July 2008, in money market funds and time deposits with certain acceptable institutions, subject to our newly implemented Short Term Investment Policy. The income earned on these investments during 2008 is reflected in the Interest income line.

Gain on derivatives not designated as hedges was $51.5 million for 2008, including a realized loss of $1.8 million and an unrealized gain of $55.4 million for the change in fair value of our natural gas commodity contracts. The decrease in natural gas prices experienced during the last half of 2008 led to substantial unrealized gains on our commodity contracts. The 2008 gain also includes a realized loss of $0.7 million and an unrealized loss of $1.4 million on our interest rate swap. As a comparison, 2007 includes an unrealized loss of $15.6 million for the changes in fair value of our commodity contracts, a realized gain of $9.5 million and a loss of $0.3 million on our interest rate swap. We will continue to be exposed to volatility in earnings resulting from changes in the fair value of our commodity contracts as we do not designate these contracts as hedges.

In July 2008, we realized a significant gain on the sale of assets related primarily to our sale of deep rights acreage to Chesapeake which helped generate income from continuing operations before taxes of $183.3 million for 2008. As a of result of the significant gain generated by the sale, we believe that we will be in a position to utilize the majority of our net operating loss carryforwards when we file our 2008 tax return. We believe it is now more likely than not that we will be able to recognize our deferred tax assets associated with these net operating loss carryforwards. As a result, we released $25.5 million of our previously booked valuation allowance in the third quarter of this year. The impact of this is to reduce income tax expense for the year to a total of $46.6 million. Primarily as a result of the Chesapeake sale, our 2008 estimated income tax liability to the State of Louisiana is $10 million, which is included in the total of $46.6 million.

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In a sale that closed March 20, 2007, we sold our assets in South Louisiana to a private company. We realized a gain of $9.7 million, net of tax, in 2007. In August 2008, we closed on the sale of our St. Gabriel field to a private company for $0.1 million. Also in August 2008, we assigned our rights in the Bayou Bouillon field to a private party for a nominal amount. We continue to hold our interests in the Plumb Bob field. Loss from discontinued operations, net of tax of $0.5 million for 2008 includes an impairment of our Plumb Bob field for $1.2 million before tax ($0.8 million net of tax) in connection with our independent engineer s report on reserves as of December 31, 2008.

Year ended December 31, 2007 compared to December 31, 2006

Interest expense was $11.9 million for 2007, compared to $7.8 million for 2006, with the increase primarily attributable to a higher level of average borrowings in 2007. With the issuance of 3.25% convertible notes in December 2006, the weighted average interest rate fell to 5.0%, a significant reduction from the prior year s 7.5%.

Loss on derivatives not designated as hedges was $6.4 million for 2007, compared to a gain of $38.1 million for 2006. The loss in 2007 includes an unrealized loss of $15.6 million for the change in fair value of our gas and oil hedges, and a realized gain of $9.5 million for the effect of settled derivatives. The loss also includes an unrealized loss of $0.5 million and a realized gain of $0.2 million on our interest rate swap. We did not designate any of our oil and gas derivates as hedges for 2007. Our natural gas hedges were ineffective 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 to justify treatment as cash flow hedges pursuant to SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities* (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.

We retired our term loan in early December 2006 with the proceeds of the 3.25% convertible senior notes offering. In the fourth quarter of 2006, we fully amortized remaining deferred loan financing costs of $0.6 million incurred in connection with the initial funding of this loan and a subsequent amendment.

Income tax expense on continuing operations of $3.0 million for 2007 includes a write off of our December 31, 2006 net deferred tax asset of $9.7 million and a tax benefit of $6.1 million to offset the tax expense related to discontinued operations. We increased our valuation allowance and reduced our net deferred tax asset to zero during 2007 after considering all available positive and negative evidence related to the realization of our deferred tax asset. Income tax expense on continuing operations of $5.1 million in 2006, which was non-cash, represents 35.5% of the pre-tax income in 2006.

In conjunction with the sale of our South Louisiana assets in March 2007, we realized a gain (loss) on disposal, net of tax, of $9.7 million ($14.9 million before tax). Income, net of tax on discontinued operations was $1.8 million for 2007 versus a loss of $7.7 million for 2006. This includes an impairment expense, before tax, of $0.4 million and $14.9 million for the years ended December 31, 2007 and 2006, respectively, on certain assets treated as held for sale. See Note 9 Discontinued Operations and Note 12 Acquisitions and Divestitures to our consolidated financial statements for further discussion of our discontinued operations.

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Liquidity

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 2009 is $300 million. We continue to evaluate our capital budget throughout the year based in part upon availability of capital, status of our drilling operations and the outlook for oil and natural gas prices. Please see Disruptions in the Credit and Capital Markets and Impact on Liquidity below.

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, 2008. In addition to the contractual obligations presented in the table, our Consolidated Balance Sheet at December 31, 2008 reflected accrued interest on our bank debt of $1.8 million payable in the first quarter of 2009. See Note 4 Long-Term Debt and Note 10 Commitments and Contingencies to our consolidated financial statements for additional information.

			Payment due by Period				
	Note	Total	2009	2010	2011	2012	2013 and After
Contractual Obligations							
Long term debt (1)	4	$ 250,000	$	$ 75,000	$ 175,000	$	$
Interest on 3.25% notes	4	16,590	5,688	5,688	5,214		
Office space leases	10	1,699	679	207	213	220	380
Office equipment leases	10	387	279	79	13	8	8
Drilling & operations contracts	10	49,261	27,675	9,174	7,956	4,456	
Transportation contracts	10	3,831	1,804	1,926	101		
Total contractual obligations		$ 321,768	$ 36,125	$ 92,074	$ 188,497	$ 4,684	$ 388

(1) The $175.0 million 3.25% 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 $13.8 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.

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 and borrowings under our revolving bank credit facility and second lien term loan. In the future, we may also access public markets to issue additional debt and/or equity securities.

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At December 31, 2008, we had excess borrowing capacity of $175.0 million under our revolving bank credit facility. Our primary sources of cash during 2008 were from net proceeds from the issuance of common stock of $191.3 million in July 2008, net proceeds from property sales of $175.1 million (primarily the Chesapeake transaction), funds generated from operations and bank borrowings. Cash was used primarily to fund exploration and development expenditures. We made aggregate cash payments of $13.0 million for interest and $14.8 million for income taxes in 2008. The table below summarizes the sources of cash during 2008, 2007 and 2006:

	Year Ended December 31,			Year Ended December 31,		
Cash flow statement information:	**2008**	**2007**	**Variance**	**2007**	**2006**	**Variance**
			(In thousands)			
Net Cash:						
Provided by operating activities	$ 107,039	$ 85,925	$ 21,114	$ 85,925	$ 65,133	$ 20,792
Used in investing activities	(187,786)	(219,193)	31,407	(219,193)	(258,737)	39,544
Provided by financing activities	223,847	131,532	92,315	131,532	179,946	(48,414)
Increase (decrease) in cash and cash equivalents	$ 143,100	$ (1,736)	$ 144,836	$ (1,736)	$ (13,658)	$ 11,922

At December 31, 2008, we had working capital of $109.8 million and long-term debt of $250.0 million. Our working capital position is primarily due to the remaining cash received from the equity offering and Chesapeake transaction in the third quarter of 2008.

Cash Flows

Year ended December 31, 2008 compared to year ended December 31, 2007

Operating activities. Cash flow from operations is dependent upon production volumes generated from our development, exploration and acquisition activities, the price of oil and natural gas and costs incurred in our operations. Our cash flow from operations is also impacted by changes in working capital. Net cash provided by operating activities was $107.0 million, an increase of $21.1 million, or 25%, from $85.9 million in 2007. Our operating revenues increased 94% in 2008 with a 51% increase in average daily production and a 29% increase in commodity prices as compared to 2007.

Investing activities. Net cash used in investing activities was $187.8 million for the year ended December 31, 2008, compared to $219.2 million for 2007. We received net proceeds of $175.1 million from sale of assets (primarily the Chesapeake transaction) compared to net proceeds of $72.3 million received from the sale of substantially all of our South Louisiana assets in 2007. Total capital expenditures of $362.8 million for 2008 increased $71.3 million from $291.5 million in 2007. We conducted drilling and completion operations on 126 gross wells in 2008 compared to 104 gross wells in 2007, an increase of 21%. Of the $362.8 million invested this year, we spent $328.8 million for drilling and completion activities, $28.6 million for leasehold acquisition, $4.2 million for facilities and infrastructure and $1.2 million for furniture, fixtures and equipment. We spent $273.8 million for drilling and completion activities and $14.3 million for facility installation activities in the Cotton Valley trend in 2007.

Financing activities. Net cash provided by financing activities was $223.8 million for 2008, an increase of $92.3 million over 2007. In January 2008, we borrowed $75.0 million on our Second Lien Term Loan and used $53.5 million of the borrowings to pay-off the balance on our revolving credit facility. In July 2008, we received net proceeds of $191.3 million from an equity offering. We used these proceeds to pay the full outstanding balance on our existing bank credit facility. We have zero borrowings outstanding under our Senior Credit Facility as of December 31, 2008.

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Year ended December 31, 2007 compared to year ended December 31, 2006

Operating activities. Net cash provided by operating activities was $85.9 million, an increase of $20.8 million or 32% from $65.1 million in 2006. A 49% increase in operating revenues resulting from a 44% increase in production volumes from continuing operations contributed to the increased cash flow in 2007. Operating cash flow amounts are net of changes in our current assets and current liabilities, which provided additional cash flow of $17.9 million and $4.9 million for the years ended December 31, 2007 and 2006, respectively, with $12.5 million of the increase in 2007 due to a year-end prepay transaction. In late 2007, one of our physical purchasers advanced $12.5 million for gas to be delivered under contract in the first quarter of 2008.

Investing activities. Net cash used in investing activities was $219.2 million for the year ended December 31, 2007, compared to $258.7 million for 2006. This includes $291.5 million in capital expenditures partially offset by $72.3 million in net proceeds from the sale of our South Louisiana assets. Of the $291.5 million, approximately $273.8 million was spent for drilling and completion activities and $14.3 million for facility installation activities in the Cotton Valley trend. We spent $211.0 million in 2006 for drilling, completion and facility installation activities.

Financing activities. Net cash provided by financing activities was $131.5 million in 2007 versus $179.9 million in 2006. The majority of our net financing cash flows came from the $123.8 million in proceeds from the issuance of common stock net of purchased capped call options, and $14.0 million in net proceeds from bank borrowings.

Disruptions in the Credit and Capital Markets and Impact on Liquidity

We have historically funded our operations from a combination of borrowings under our bank facilities, accessing the capital markets and cash flow from operations. There have been significant disruptions in the U.S. and global credit and capital markets. In recent months, the volatility and disruption have reached unprecedented levels. In some cases, the markets have exerted downward pressure on stock prices and credit capacity for certain issuers. We believe that with prices as of December 31, 2008, we can fund up to $300 million of capital expenditures in 2009 from available cash and cash flow from operations without borrowing under our senior credit facility. We have approximately $147.5 million of cash on hand and $175.0 million of undrawn capacity available under our senior credit facility that matures in February 2010. Availability under our credit facility is subject to semi-annual borrowing base redeterminations, set at the discretion of our lenders. Both we and our lenders also have the discretion to call for at least one additional redetermination per year. The borrowing base is calculated by our lenders based on their valuation of our proved reserves utilizing our reserve reports and their internal decisions. There is no assurance that we can sustain or increase our borrowing base, which if reduced will reduce our borrowing capacity. Because we control the timing of a substantial portion of our capital expenditures and will manage such expenditures accordingly, we do not anticipate an immediate need for borrowings under our senior credit facility or access to the capital markets for the duration of 2009. Accordingly, we may adjust our capital budget further based on further evaluations of our available funding, the status of our drilling operations and the outlook for oil and natural gas prices.

As our senior credit facility is set to expire in February 2010, we are planning to explore refinancing alternatives in the near future. Given the current state of the bank markets, there can be no assurance that a replacement facility will provide similar borrowing capacity, nor do we expect to replace the facility without paying materially higher fees and higher rates on drawn borrowings.

3.25% Convertible Senior Notes

In December 2006, we sold $175.0 million of 3.25% convertible senior notes (the notes) due in December 2026. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes are our senior unsecured obligations and 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 interest is paid semi-annually on June 1 and December 1. Interest payments on the notes began on June 1, 2007.

Before December 1, 2011, we may not redeem the notes. On or after December 11, 2011, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of December 11, 2011, 2016 and 2021. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares. 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

In connection with the offering of the notes we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell the shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from the common stock offerings and lending transactions under this agreement. 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 the notes to shares pursuant to the terms of the indenture governing the notes.

The Share Lending Agreement also requires BSC to post collateral of our common stock if its credit rating is below either A3 by Moody s Investors Service (Moody s) or A- by Standard and Poor s (S&P). As a result of the long term ratings downgrade of BSC in March 2008, BSC was required to return all or a portion of the borrowed shares or collateralize the return obligation with cash or highly liquid non-cash collateral. On March 20, 2008, BSC had returned 1,497,963 shares of the 3,122,263 originally borrowed shares and fully collateralized the remaining 1,624,300 borrowed shares with a cash collateral deposit of approximately $41.3 million. This amount represents the market value of the remaining borrowed shares at March 20, 2008. Under certain conditions, BSC is required to maintain collateral value in the amount at least equal to the market value of the outstanding borrowed shares. The 1,497,963 shares returned to us were recorded as treasury stock and retired in March 2008.

The 1,624,300 shares of common stock outstanding as of December 31, 2008, under the Share Lending Agreement are required to be returned to us in the future. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. As a result, the shares of common stock lent under the Share Lending Agreement have no impact on the earnings per share calculation.

In May 2008, JP Morgan Chase & Co. completed its acquisition of The Bear Stearns Companies Inc. JP Morgan Chase & Co. s credit rating exceeds that required by the Share Lending Agreement. Thus, collateral is no longer required. Should JP Morgan Chase & Co. s credit ratings decline below either A3 by Moody s or A- by S&P, it would be required to post collateral to support its obligation to return any remaining borrowed shares.

Senior Credit Facility

On November 17, 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (as amended, the Senior Credit Facility) and a term loan that expanded our borrowing capabilities. Total lender commitments under the Senior Credit Facility were $200 million, and the Senior Credit Facility matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are

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limited to, and subject to periodic redeterminations of the borrowing base. At December 31, 2008, we had a borrowing base of $175.0 million and no amounts outstanding under the Senior Credit Facility. Pursuant to the terms of our Senior Credit Facility, the next redetermination of our borrowing base will be March 31, 2009. Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.00% to 0.75%, or LIBOR plus 1.25% to 2.25%, depending on borrowing base utilization.

Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

The terms of the Senior Credit Facility, as amended, require us to maintain certain covenants. Capitalized terms used, but not defined, here have the meanings assigned to them in the Senior Credit Facility. As of December 31, 2008, we were in compliance with all of the financial covenants of our Senior Credit Facility. The covenants in effect at December 31, 2008 include:

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio of not less than 3.0/1.0 for the trailing four quarters;
- Total Debt of no greater than 3.0 times EBITDAX for the trailing four quarters (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives, but exclude unrealized gains (losses) from derivatives. The 3.25% convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio.); and
- Asset coverage ratio (defined as the present value of proved reserves discounted at 10% divided by total debt, excluding 3.25% convertible senior notes) of not less than 1.5 to 1.0.

Second Lien Term Loan

On January 16, 2008, we entered into a new Second Lien Term Loan Agreement which provides for a 3-year, non-revolving loan of $75.0 million and is due in a single maturity on December 31, 2010. We have no rights to prepay in the first year. Voluntary prepayment rights in the second year are at 101% of par, and thereafter at par. Interest on the Second Lien Term Loan accrues at a rate of LIBOR plus 550 basis points and is payable quarterly in arrears. As of December 31, 2008, we were in compliance with all of the financial covenants of our Second Lien Term Loan. The terms of the Second Lien Term Loan Agreement contain financial covenants which include:

- Asset coverage ratio (defined as the present value of proved reserves discounted at 10% divided by total debt, excludes 3.25% convertible senior notes) of not less than 1.5 to 1.0;
- Total debt to EBITDAX ratio of not more than 3.0 to 1.0 (total debt to exclude the 3.25% convertible senior notes); and
- EBITDAX to interest expense ratio of not less than 3.0 to 1.0.

Capped Call Option Transactions

On December 10, 2007, we closed the public offering of 6,430,750 shares of our common stock at a price of $23.50 per share. Net proceeds from the offering were approximately $145.4 million after deducting the underwriters discount and estimated offering expenses. We used approximately $123.8 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility and approximately $21.6 million of the net proceeds to purchase capped call options on shares of our common stock from affiliates of BSC and JP Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. One third of the options will expire over each of three separate multi-day settlement periods beginning approximately 18 months, 24 months and 30 months from the closing of the offering, respectively.

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The capped call option transactions are expected to result in our receipt, on a net share, cashless basis of a certain number of shares of our common stock if the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for the relevant tranche is greater than the lower call strike price of the capped call option transactions. We refer to the amount by which the market value per share exceeds the lower call strike price as an in-the-money amount for the relevant tranche of the capped call option transaction. The in-the-money amount will never exceed the difference between the upper call strike price and the lower call strike price (i.e., it will be capped). The lower call strike price is $23.50, which corresponds to the price to the public in the equity offering and the upper call strike price is $32.90, which corresponds to 140% of the price to the public in the offering. Both lower and upper call strike prices are subject to customary anti-dilution and certain other adjustments. The number of shares of our common stock that we will receive from the option counterparties upon expiration of each tranche of the capped call option transactions will be equal to the in-the-money amount of that tranche divided by the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for that tranche. If the stock price is equal to the upper call strike price of $32.90 on each of the settlement dates, we will recoup up to 1.6 million shares.

The capped call option agreements were separate transactions entered into by us with the option counterparties and were not part of the terms of the offering of common stock.

The capped call option agreements require an option counterparty to transfer their rights and obligations within 30 days if their credit rating is below either Baa1 by Moody s or BBB+ by S&P. As a result of the ratings downgrade of BSC on March 14, 2008, BSC was obligated to transfer their rights and obligations under the capped call option agreement to a suitable counterparty (one with a credit rating of at least BBB+ by S&P and Baa1 by Moody s within 30 days). BSC s obligation to transfer its rights and obligations to an entity with a higher credit rating was cured by a ratings upgrade on March 24, 2008.

During the second quarter of 2008, BSC sold its position in the capped call options to Bank of America.

Equity Offering

On July 14, 2008, we closed the public offering of 3,121,300 shares of our common stock at a price of $64.00 per share. Net proceeds from the offering were approximately $191.3 million after deducting the underwriters discount and estimated offering expenses. We used approximately $96.0 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility. We used the remaining net proceeds for general corporate purposes, including funding a portion of our remaining 2008 drilling program, other capital expenditures and working capital requirements.

Short Term Investments

The net proceeds from our July 2008 equity offering and the net proceeds from sale of assets were invested in short term investments. As of December 31, 2008, our short term investments amounted to $136.5 million. Prior to making these investments, our board of directors instituted a short term investment policy, to be implemented by our Chief Executive Officer and Chief Financial Officer. The short term investment policy was adopted to meet the following objectives:

Preserve principal;

Maintain liquidity;

Diversify investment risk; and

Maximize earnings on surplus funds consistent with the first three objectives.

This new policy also authorizes transactions only with institutions that meet the following criteria:

Short-term debt ratings of at least A1 by Standard and Poor s (S&P) and P1 by Moody s;

- Long-term debt ratings of at least AA- by S&P and Aa3 by Moody s; and

- Market capitalization of at least $25.0 billion for the parent company at the time of the transaction.

Also, funds on deposit at any one institution shall not exceed $100.0 million, unless previously approved by our Chief Financial Officer and Chief Executive Officer.

As of December 31, 2008, we held short term investments in money market funds with three institutions meeting all of these criteria. Short term investments as of December 31, 2008, carried maturities of fourteen days or less and are considered cash equivalents. We will continue to monitor these institutions in light of the current financial market crisis and in accordance with our policy.

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.

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.

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

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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 before 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.

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.

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 used by us. We cannot predict the types of reserve revisions that will be required in future periods.

Successful efforts accounting

We use the successful efforts method to account for exploration and development expenditures and to calculate DD&A. 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.

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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. In July 2008, we realized a significant gain on sale of assets which helped generate income from continuing operations before taxes of $183.3 million for 2008. As a result of the significant gain generated by the sale, we believe that we will be in a position to utilize the majority of our net operating loss carryforwards when we file our 2008 tax return. We believe it is now more likely than not that we will be able to recognize our deferred tax assets associated with these net operating loss carryforwards. As a result, we released $25.5 million of our previously booked valuation allowance in the third quarter of this year.

FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*, provides guidance on recognition and measurement of uncertainties in income taxes. FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. See Notes 1 and 6 to our consolidated financial statements.

Fair Value Measurement

Derivative instruments are carried at fair value. Recurring fair value measurements at interim periods and annually use quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data correlation or other means. These measurements fall within level 2 of the fair value hierarchy of SFAS 157.

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.

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Off-Balance Sheet Arrangements

We do not currently use 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, 2008, the commodity hedges we use were in the form of:

(a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX and field 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 Derivative Activities to our consolidated financial statements for additional information. At December 31, 2008, we had the following commodity hedges in place (in millions):

Collars (NYMEX)	**Daily Volume**	**Total Volume**	**Average Floor/Cap**	
Natural gas (MMBtu)				
1Q 2009	20,000	1,800,000	$ 8.75	$13.10
2Q 2009	20,000	1,820,000	$ 8.75	$13.10
3Q 2009	20,000	1,840,000	$ 8.75	$13.10
4Q 2009	20,000	1,840,000	$ 8.75	$13.10

Swaps (NYMEX)			**Average Price**
Natural gas (MMBtu)			
1Q 2009	20,000	1,800,000	$8.83
2Q 2009	20,000	1,820,000	$8.83

3Q 2009	20,000	1,840,000	$8.83
4Q 2009	20,000	1,840,000	$8.83

Swaps (TexOk)			**Price (1)**
Natural gas (MMBtu)			
1Q 2009	20,000	1,800,000	$7.87
2Q 2009	20,000	1,820,000	$7.87
3Q 2009	20,000	1,840,000	$7.87
4Q 2009	20,000	1,840,000	$7.87

(1) The index price is based upon Natural Gas Pipeline of America, TexOk (NGPLTXOK) zone as published in the Inside FERC. The comparable index price based on NYMEX was approximately $8.25/Mmbtu.

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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 2009. The fair value of the natural gas hedging contracts in place at December 31, 2008, resulted in a current asset of $55.3 million. Based on gas pricing in effect at December 31, 2008, a hypothetical 10% increase in gas prices would have resulted in a current derivative asset of $42.5 million while a hypothetical 10% decrease in gas prices would have increased the current derivative asset to $69.2 million.

We have entered into the following contracts subsequent to December 31, 2008:

(a) A NGPLTXOK priced basis swap contract with the Bank of Montreal for 20,000 Mmbtu per day for the months of March through December 2009, locking in a fixed basis to the Company of $0.52 per Mmbtu, and

(b) A NGPLTXOK priced basis swap contract with BNP for 20,000 Mmbtu per day for the months of March through December 2009 locking in a fixed basis to the Company of $0.52 per Mmbtu.

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, 2008, we had the following interest rate swaps in place with BNP and BMO (in millions):

Effective Date	Maturity Date	Libor Swap Rate	Notional Amount (Millions)	Fair Value (Dollars)
2/26/2007	2/26/2009	4.860%	$ 40.0	$ (271,029)
4/22/2008	4/22/2010	3.191%	25.0	(515,584)
4/22/2008	4/22/2010	3.191%	50.0	(1,017,416)
				$ (1,804,029)

The fair value of the interest rate swap contracts in place at December 31, 2008, resulted in a current liability of $1.2 million and a long term liability of $0.6 million. Based on interest rates at December 31, 2008, a hypothetical 10% increase in interest rates would have decreased the liability to $1.6 million whereas a 10% decrease in interest rates would have increased the liability to $2.0 million.

Item 8. ***Financial Statements and Supplementary Data***

The information required here is included in the report as set forth in the Index to Consolidated Financial Statements on page F-1.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is recorded, processed, summarized and reported to our management

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including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by SEC rule 13a-15(b), we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(c) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of December 31, 2008, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008, is set forth on page F-2 of this Annual Report on Form 10-K and is incorporated by reference herein.

Ernst & Young LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008, as stated in their report which is included herein on page F-3.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. ***Other Information***

None.

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PART III

Item 10. *Directors and Executive Officers of the Registrant and Corporate Governance*

Our executive officers and directors and their ages and positions as of February 27, 2009, are as follows:

Name	Age	Position
Patrick E. Malloy, III	66	Chairman of the Board of Directors
Walter G. Gil Goodrich	50	Vice Chairman, Chief Executive Officer and Director
Robert C. Turnham, Jr.	51	President, Chief Operating Officer and Director
David R. Looney	52	Executive Vice President and Chief Financial Officer
Mark E. Ferchau	54	Executive Vice President
Michael J. Killelea	46	Senior Vice President, General Counsel and Corporate Secretary
Henry Goodrich	78	Chairman Emeritus and Director
Josiah T. Austin	62	Director
Geraldine A. Ferraro	73	Director
Michael J. Perdue	54	Director
Arthur A. Seeligson	50	Director
Stephen M. Straty	53	Director
Gene Washington	62	Director

Patrick E. Malloy, III became Chairman of the Board of Directors in February 2003. He has been President and Chief Executive Officer of Malloy Enterprises, Inc., a real estate and investment holding company since 1973. In addition, Mr. Malloy served as a director of North Fork Bancorporation, Inc. (NYSE) from 1998 to 2002 and was Chairman of the Board of New York Bancorp, Inc. (NYSE) from 1991 to 1998. He joined the Company s Board in May 2000.

Walter G. Gil Goodrich became Vice Chairman of the Board of Directors in February 2003. He has served as the Company s Chief Executive Officer since August 1995. Mr. Goodrich was Goodrich Oil Company s Vice President of Exploration from 1985 to 1989 and its President from 1989 to August 1995. He joined Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company, as an exploration geologist in 1980. Gil Goodrich is the son of Henry Goodrich. He has served as one of the Company s directors since August 1995.

Robert C. Turnham, Jr. has served as the Company s Chief Operating Officer since August 1995 and became President and Chief Operating Officer in February 2003. Mr. Turnham joined the Board of Directors of the Company in December 2006. He has held various positions in the oil and natural gas business since 1981. From 1981 to 1984, Mr. Turnham served as a financial analyst for Pennzoil. In 1984, he formed Turnham Interests, Inc. to pursue oil and natural gas investment opportunities. From 1993 to August 1995, he was a partner in and served as President of Liberty Production Company, an oil and natural gas exploration and production company.

David R. Looney joined us as Executive Vice President and Chief Financial Officer in May 2006. Mr. Looney has over twenty-nine years of experience in the energy finance business, most recently as the Executive Vice President and Chief Financial Officer of Energy Partners, Ltd., a publicly traded E&P company, from March 2005 to April 2006 and Vice President, Finance and Treasurer of EOG Resources, Inc., one of the largest publicly traded E&P Companies in the U.S., from August 1999 to February 2005.

Mark E. Ferchau became Executive Vice President in April 2004. From February 2003 to April 2004, he served as our Senior Vice President, Engineering and Operations, after initially joining us as Vice President in September 2001. Mr. Ferchau previously worked in the divestment group of Forest Oil Corporation, an oil and gas exploration and production company, from December 2000 to September 2001 after the merger with Forcenergy Inc. Before the merger, he served as Production Manager for Forcenergy Inc., a publicly-held oil and

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gas exploration and production company, from October 1997 to December 2000. From July 1993 to October 1997, he held various positions including Vice President, Engineering of Convest Energy Corporation and Edisto Resources Corporation, which were publicly-held oil and gas exploration and development companies. From June 1982 to July 1993, Mr. Ferchau held various positions with Wagner & Brown, Ltd., a privately held oil and gas exploration and development company. Prior thereto, he held various positions with various independent oil and gas exploration and development companies and oilfield service companies.

Michael J. Killelea joined the Company as Senior Vice President, General Counsel and Corporate Secretary in January 2009. Mr. Killelea has over 20 years of experience in the energy industry. From June 2008 through November 2008, he served as Vice President, General Counsel and Corporate Secretary for Maxus Energy Corporation, a private oil and gas exploration and production company located in The Woodlands, Texas. Prior to that time, Mr. Killelea was Senior Vice President, General Counsel and Corporate Secretary of Pogo Producing Company, a publicly traded oil and gas exploration and production company headquartered in Houston, Texas, from March 2000 until the sale of Pogo Producing Company to Plains Exploration Company in November 2007.

Henry Goodrich is the Chairman of the Board of Directors Emeritus. Mr. Goodrich began his career as an exploration geologist with the Union Producing Company and McCord Oil Company in the 1950 s. From 1971 to 1975, Mr. Goodrich was President, Chief Executive Officer and a partner of McCord-Goodrich Oil Company. In 1975, Mr. Goodrich formed Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company. He was elected to our board in August 1995, and served as Chairman of the Board from March 1996 through February 2003. Henry Goodrich is the father of Walter G. Goodrich.

Josiah T. Austin is the managing member of El Coronado Holdings, L.L.C., a privately owned investment holding company. He and his family own and operate agricultural properties in the state of Arizona and Sonora, Mexico through El Coronado Ranch & Cattle Company, L.L.C. and other entities. Mr. Austin previously served on the Board of Directors of Monterey Bay Bancorp of Watsonville, California, and is a prior board member of New York Bancorp, Inc., which merged with North Fork Bancorporation, Inc. (NYSE) in early 1998. He was elected to the Board of Directors of North Fork Bancorporation, Inc. in May 2004. He became one of our directors in August 2002.

Geraldine A. Ferraro is Of Counsel to Blank Rome LLP, a national law firm, and a Principal of Blank Rome LLC, a national law firm. Before joining Blank Rome in February 2007, Ms. Ferraro was head of the Public Affairs Practice of The Global Consulting Group, a New York-based international investor relations and corporate communications firm. Ms. Ferraro served as a Member of Congress for three terms before accepting the Democratic nomination for vice-president in 1984. She is a Board member of the National Democratic Institute of International Affairs and a member of the Council on Foreign Relations and was formerly United States Ambassador to the United Nations Human Rights Commission. Ms. Ferraro has been affiliated with numerous public and private sector organizations, including serving as a director of the former New York Bancorp, Inc., a NYSE-listed company. She was elected to our Board of Directors in August 2003.

Michael J. Perdue is the President of PacWest Bancorp, a publicly traded holding company and of Pacific Western Bank, a subsidiary of the holding company, based in San Diego, California. Before assuming his present position in October 2006, Mr. Perdue was President and Chief Executive Officer of Community Bancorp Inc., from July 2003. Before Community Bancorp Inc. Mr. Perdue was Executive Vice President of Entrepreneurial Corporate Group and President of its subsidiary, Entrepreneurial Capital Corporation. From September 1993 to April 1999, Mr. Perdue served in executive positions with Zions Bancorporation and FP Bancorp, Inc., as a result of FP Bancorp s acquisition by Zions Bancorporation in May 1998. He has also held senior management positions with Ranpac, Inc., a real estate development company, and PacWest Bancorp. He was elected to our Board of Directors in January 2001.

Arthur A. Seeligson is currently engaged in the management of his personal investments in Houston, Texas. Previously, Mr. Seeligson was an investment banker focused on the oil and gas industry. In that capacity, he was

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Vice President, Energy Corporate Finance and Principal, Corporate Finance for Schroder Wertheim & Company and Wasserstein, Perella & Co., respectively, in their Houston offices. He has been primarily engaged in the management of his personal investments since 1995 and is the Managing Partner of Seeligson Oil Co. Ltd. He has served as a director since August 1995.

Stephen M. Straty is the Co-Head and a Managing Director of Jefferies Randall & Dewey, the Energy Investment Banking Group at Jefferies. Mr. Straty joined the firm in June 2008 and has nearly 30 years of experience in finance, most recently as Senior Managing Director and Head of the Natural Resources Group at Bear, Stearns & Co., Inc. where he worked for 17 years. Mr. Straty has extensive experience in serving a broad array of energy clients, having completed over $40.0 billion in merger and acquisition and financing assignments during the past ten years. Previously, he spent ten years at Smith Barney, Harris, Upham & Co. focusing on the energy sector, and prior to that, he worked in investment banking at Prudential Insurance, advising on private placements of debt and equity as well as leveraged buyouts. Mr. Straty received MBA and BA degrees with highest honors at The University of Texas at Austin.

Gene Washington is the Director of Football Operations with the National Football League (NFL) in New York. He previously served as a professional sportscaster and as Assistant Athletic Director for Stanford University before assuming his present position with the NFL in 1994. Mr. Washington serves and has served on numerous corporate and civic boards, including serving as a director for Delia s, a NYSE-listed company as well as a director of the former New York Bancorp, Inc., a NYSE-listed company. He was elected to our Board of Directors in June 2003.

Additional information required under Item 10, Directors and Executive Officers of the Registrant and Corporate Governance, will be provided in our Proxy Statement for the 2009 Annual Meeting of Stockholders. Additional information regarding our corporate governance guidelines as well as the complete texts of its Code of Business Conduct and Ethics and the charters of our Audit Committee, Compensation Committee and our Nominating and Corporate Governance Committee may be found on our website at *www.goodrichpetroleum.com.*

Item 11. ***Executive Compensation***

The information required by this Item is incorporated by reference to the information provided under the caption Executive Compensation in our definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management***

The information required by this Item is incorporated by reference to the information provided under the caption Security Ownership of Certain Beneficial Owners and Management in our definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

Item 13. ***Certain Relationships and Related Transactions and Director Independence***

The information required by this Item is incorporated by reference to the information provided under the caption Transactions with Related Persons and Corporate Governance-Our Board-Board Size; Director Independence in our definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

Item 14. ***Principal Accounting Fees and Services***

The information required by this Item is incorporated by reference to the information provided under the caption Audit and Non-Audit Fees in our definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

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PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) (1) and (2) Financial Statements and Financial Statement Schedules

See Index to Consolidated Financial Statements on page F-1.

All schedules are omitted because they are not applicable, not required or the information is included within the consolidated financial information or related notes.

(a) (3) Exhibits

2.1	Purchase and Sale Agreement dated May 23, 2008 by and between Goodrich Petroleum Corporation and Caddo Resources LP (Incorporated by reference to Exhibit 2.1 of the Company s Form 8-K filed on May 29, 2008.)
2.2	Purchase and Sale Agreement dated June 15, 2008 by and between Goodrich Petroleum Company, LLC and Chesapeake Louisiana, LP (Incorporated by reference to Exhibit 2.1 of the Company s Form 9-K filed on June 17, 2008.)
3.1	Restated Certificate of Incorporation of Goodrich Acquisition II, Inc. dated January 31, 1997 (Incorporated by reference to Exhibit 3.1 A of the Company s Third Amended Registration Statement on Form S-1 (Registration No. 333-47078) filed on December 8, 2000).
3.2	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Acquisition II, Inc., dated January 31, 1997 (Incorporated by reference to Exhibit 3.1 B of the Company s Third Amended Registration Statement of Form S-1 (Registration No. 333-47078) filed on December 8, 2000.
3.3	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated March 12, 1998 (Incorporated by reference to Exhibit 3.2 of the Company s Annual Report on Form 10-K for the year ended December 31, 1997).
3.4	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated May 9, 2002 (Incorporated by reference to Exhibit 3.4 of the Company s Current Report on Form 8-K filed on December 3, 2007).
3.5	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated May 30, 2007 (Incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2007).
3.6	Bylaws of the Company, as amended and restated (Incorporated by reference to Exhibit 3.2 of the Company s Form 8-K filed February 19, 2008).
3.7	Certificate of Designation of 5.375% Series B Cumulative Convertible Preferred Stock (Incorporated by reference to Exhibit 1.1 of the Company s Form 8-K filed on December 22, 2005).
4.1	Specimen Common Stock Certificate (Incorporated by reference to Exhibit 4.6 of the Company s Registration Statement filed February 20, 1996 on Form S-8 (File No. 33-01077)).
4.2	Registration Rights Agreement dated December 21, 2005 among the Company, Bear, Sterns & Co. Inc. and BNP Paribas Securities Corp. (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 22, 2005).
4.3	Goodrich Petroleum Corporation 2006 Long-Term Incentive Plan (Incorporated by reference to the Company s Proxy Statement filed April 17, 2006).

4.4	Form of Grant of Restricted Phantom Stock (1995 Stock Option Plan) (Incorporated by reference to Exhibit 4.2 to the Company s Registration Statement on Form S-8 filed on October 23, 2006).
4.5	Form of Grant of Restricted Phantom Stock (2006 Long-Term Incentive Plan) (Incorporated by reference to Exhibit 4.3 to the Company s Registration Statement on Form S-8 filed on October 23, 2006).

4.6	Form of Director Stock Option Agreement (with vesting schedule) (Incorporated by reference to Exhibit 4.4 to the Company s Registration Statement on Form S-8 filed on October 23, 2006).
4.7	Form of Director Stock Option Agreement (immediate vesting) (Incorporated by reference to Exhibit 4.5 to the Company s Registration Statement on Form S-8 filed on October 23, 2006).
4.8	Form of Incentive Stock Option Agreement (Incorporated by reference to Exhibit 4.6 to the Company s Registration Statement on Form S-8 filed on October 23, 2006).
4.9	Form of Nonqualified Option Agreement (Incorporated by reference to Exhibit 4.7 to the Company s Registration Statement on Form S-8 filed on October 23, 2006).
4.10	Registration Rights Agreement dated December 6, 2006 among Goodrich Petroleum Corporation, Bear, Sterns & Co. Inc., Deutsche Bank Securities Corp. and BNP Paribas Securities Corp (Incorporated by reference to Exhibit 4.11 of the Company s Annual Report on Form 10-K for the year ended December 31, 2006).
4.11	Indenture, dated December 6, 2006, between Goodrich Petroleum Corporation and Wells Fargo Bank, National Association, as Trustee (Incorporated by reference to Exhibit 4.12 of the Company s Annual Report on Form 10-K for the year ended December 31, 2006).
4.12	Registration Rights Agreement dated May 23, 2008 between Goodrich Petroleum Corporation and Caddo Resources, LP (Incorporated by reference to Exhibit 4.1 of the Company s Form 8-K filed on May 29, 2008).
10.1	Goodrich Petroleum Corporation 1995 Stock Option Plan (Incorporated by reference to Exhibit 10.21 to the Company s Registration Statement filed May 30, 1995 on Form S-4 (File No. 33-58631)).
10.2	Consulting Services Agreement between Patrick E. Malloy and Goodrich Petroleum Corporation dated June 1, 2001 (Incorporated by reference to Exhibit 10.3 of the Company s Annual Report filed on Form 10-K for the year ended December 31, 2001 (File No. 001-12719)).
10.3	Goodrich Petroleum Corporation 1997 Non-Employee Director Compensation Plan (Incorporated by reference to the Company s Proxy Statement filed April 27, 1998 (File No. 001-12719)).
10.4	Form of Subscription Agreement dated September 27, 1999 (Incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K dated October 15, 1999 (File No. 001-12719)).
10.5	Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated February 25, 2005 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on April 21, 2005).
10.6	Severance Agreement between the Company and Walter G. Goodrich, dated April 25, 2003 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on April 21, 2005).
10.7	Severance Agreement between the Company and Robert C. Turnham, Jr., dated April 25, 2003 (Incorporated by reference to Exhibit 10.3 of the Company s Form 8-K filed on April 21, 2005).
10.8	Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated November 17, 2005 (Incorporated by reference to Exhibit 4.2 of the Company s Form 8-K filed on November 23, 2005).
10.9	First Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated as of December 14, 2005 (Incorporated by reference to Exhibit 4.1 of the Company s Form 8-K filed on December 20, 2005).
10.10	Second Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas, dated as of June 21, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2006).

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10.11	Third Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of August 30, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 6, 2006).
10.12	Share Lending Agreement, dated November 30, 2006, among Goodrich Petroleum Corporation, Bear, Stearns & Co. Inc. and Bear Stearns International Limited (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 4, 2006).
10.13	Fourth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of November 30, 2006 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on December 4, 2006).
10.14	Severance Agreement with David R. Looney dated May 8, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 10, 2007).
10.15	Severance Agreement with Mark E. Ferchau dated April 1, 2005 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on January 10, 2007).
10.16	Purchase and Sale Agreement, dated January 12, 2007, among Goodrich Petroleum Corporation, Malloy Energy Company, LLC and Hilcorp Energy I, L.P. (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 19, 2007).
10.17	Goodrich Petroleum Corporation Annual Bonus Plan (Incorporated by reference to Exhibit 10.5 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.18	First Amendment to Severance Agreement between the Company and Walter G. Goodrich, dated April 11, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on April 16, 2007).
10.19	First Amendment to Severance Agreement between the Company and Robert C. Turnham, Jr. dated April 11, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on April 16, 2007).
10.20	First Amendment to Severance Agreement between the Company and David R. Looney dated April 11, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Form 8-K filed on April 16, 2007).
10.21	First Amendment to Severance Agreement between the Company and Mark E. Ferchau dated April 11, 2007 (Incorporated by reference to Exhibit 10.4 of the Company s Form 8-K filed on April 16, 2007).
10.22	Second Amendment to Severance Agreement between the Company and Robert C. Turnham, Jr. dated May 17, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on May 21, 2007).
10.23	Second Amendment to Severance Agreement between the Company and David R. Looney dated May 17, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Form 8-K filed on May 21, 2007).
10.24	Second Amendment to Severance Agreement between the Company and Mark E. Ferchau dated May 17, 2007 (Incorporated by reference to Exhibit 10.4 of the Company s Form 8-K filed on May 21, 2007).
10.25	Second Amendment to Severance Agreement between the Company and James B. Davis dated May 17, 2007 (Incorporated by reference to Exhibit 10.5 of the Company s Form 8-K filed on May 21, 2007).
10.26	Second Amendment to Severance Agreement between the Company and Walter G. Goodrich dated May 17, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on May 23, 2007).

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10.27	Fifth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of August 7, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2007).
10.28	Sixth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of September 17, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 21, 2007).
10.29	Seventh Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of September 25, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 28, 2007).
10.30	Amended and Restated Severance Agreement between the Company and Walter G. Goodrich dated November 5, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.31	Amended and Restated Severance Agreement between the Company and Robert C. Turnham, Jr. dated November 5, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.32	Amended and Restated Severance Agreement between the Company and David R. Looney dated November 5, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.33	Amended and Restated Severance Agreement between the Company and Mark E. Ferchau dated November 5, 2007 (Incorporated by reference to Exhibit 10.4 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.34	Eight Amendments to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of November 30, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 3, 2007).
10.35	Capped Call Option Confirmation among Goodrich Petroleum Corporation and Bear, Stearns International Limited, dated December 4, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 10, 2007).
10.36	Capped Call Option Confirmation among Goodrich Petroleum Corporation and JP Morgan Chase Bank, National Association, dated December 4, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on December 10, 2007).
10.37	Ninth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of January 11, 2008 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 17, 2008).
10.38	Second Lien Term Loan Agreement among Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of January 16, 2008 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on January 17, 2008).
10.39	Non-employee Director Compensation Summary.
*12.1	Ratio of Earnings to Fixed Charges.
*12.2	Ratio of Earnings to Fixed Charges and Preference Securities Dividends.
16.1	Letter from KPMG LLP (Incorporated by reference to Exhibit 16.1 of the Company s 8-K filed on March 20, 2008).

21	Subsidiaries of the Registrant:
	Goodrich Petroleum Company LLC-Organized in the State of Louisiana.
	Goodrich Petroleum Company-Lafitte, LLC-organized in the State of Louisiana.
	Drilling & Workover Company, Inc.-incorporated in the State of Louisiana.
	LECE, Inc.-incorporated in the State of Texas.
*23.1	Consent of Ernst & Young LLP - Independent Registered Public Accounting Firm.
*23.2	Consent of KPMG LLP-Independent Registered Public Accounting Firm.
*23.3	Consent of Netherland, Sewell & Associates, Inc.
*24.1	Power of Attorney (included on signature page hereto).
*31.1	Certification by Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by Chief Financial Officer Pursuant to 15 U.S.C. Section 7241 as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.1	Certification by Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification by Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
** Furnished herewith.
Denotes management contract or compensatory plan or arrangement.

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GLOSSARY OF CERTAIN OIL AND GAS TERMS

As used herein, the following terms have specific meanings as set forth below:

Bbls	Barrels of crude oil or other liquid hydrocarbons
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent
MMBbls	Million barrels of crude oil or other liquid hydrocarbons
MMBtu	Million British thermal units
MMcf	Million cubic feet of natural gas
MMcfe	Million cubic feet equivalent
MMBoe	Million barrels of crude oil or other liquid hydrocarbons equivalent
SEC	United States Securities and Exchange Commission
U.S.	United States

Crude oil and other liquid hydrocarbons are converted into cubic feet of gas equivalent based on six Mcf of gas to one barrel of crude oil or other liquid hydrocarbons.

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

Dry hole is a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well is a well drilled to find and produce oil or natural gas reserves in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease or license assigns the working interest or a portion thereof to another party who desires to drill on the leased or licensed acreage. Generally, the assignee is required to drill one or more wells to earn its interest in the acreage. The assignor (the farmor) usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

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

PV-10 is the pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions).

Productive well is a well that is producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Proved reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, can be recovered in future years from known reservoirs under existing

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economic and operating conditions. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests.

Proved developed reserves are the portion of proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves are the portion of proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover is a series of operations on a producing well to restore or increase production.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GOODRICH PETROLEUM CORPORATION

By: /s/ WALTER G. GOODRICH
Walter G. Goodrich

Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints Walter G. Goodrich and David R. Looney and each of them, his true and lawful attorney-in-fact and agent, with full powers of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission granting to said attorneys-in-fact, and each of them, full power and authority to perform any other act on behalf of the undersigned required to be done in connection therewith.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant in the capacities indicated on February 27, 2009.

Signature	**Title**
/s/ WALTER G. GOODRICH **Walter G. Goodrich**	Vice Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ DAVID R. LOONEY **David R. Looney**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JAN L. SCHOTT **Jan L. Schott**	Vice President and Controller (Principal Accounting Officer)
/s/ PATRICK E. MALLOY, III **Patrick E. Malloy, III**	Chairman of Board of Directors
/s/ ROBERT C. TURNHAM. JR.	President, Chief Operating Officer and Director

Robert C. Turnham, Jr.	
/s/ Josiah T. Austin	Director
Josiah T. Austin	
/s/ Geraldine A. Ferraro	Director
Geraldine A. Ferraro	
/s/ Henry Goodrich	Director
Henry Goodrich	

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Signature	Title
/s/ Michael J. Perdue	Director
Michael J. Perdue	
/s/ Arthur A. Seeligson	Director
Arthur A. Seeligson	
/s/ Stephen M. Straty	Director
Stephen M. Straty	
/s/ Gene Washington	Director
Gene Washington	

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

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MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROLS

OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and board of directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in Internal Control Integrated Framework, we have concluded that our internal control over financial reporting was effective as of December 31, 2008. The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included on page F-3.

Management of Goodrich Petroleum Corporation

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of

Goodrich Petroleum Corporation:

We have audited Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Goodrich Petroleum Corporation s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Annual Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Goodrich Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2008 consolidated financial statements of Goodrich Petroleum Corporation and subsidiaries and our report dated February 27, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 27, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of

Goodrich Petroleum Corporation

We have audited the accompanying consolidated balance sheet of Goodrich Petroleum Corporation and subsidiaries as of December 31, 2008, and the consolidated related statements of operations, cash flows, stockholders equity, and comprehensive income (loss) for the year then ended. These 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 audit.

We conducted our audit in accordance with the 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Goodrich Petroleum Corporation and subsidiaries at December 31, 2008, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 27, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Goodrich Petroleum Corporation:

We have audited the accompanying consolidated balance sheet of Goodrich Petroleum Corporation and Subsidiaries as of December 31, 2007, and the related consolidated statements of operations, cash flows, stockholders equity and comprehensive income (loss) for each of the years in the two-year period ended December 31, 2007. 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 the 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, 2007, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas

March 13, 2008

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(In Thousands)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 147,548	$ 4,448
Accounts receivable, trade and other, net of allowance	7,019	8,539
Accrued oil and gas revenue	15,595	12,200
Fair value of oil and gas derivatives	55,276	2,267
Assets held for sale	13	311
Prepaid expenses and other	2,778	904
Total current assets	228,229	28,669
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	1,107,400	723,239
Furniture, fixtures and equipment	3,171	1,932
	1,110,571	725,171
Less: Accumulated depletion, depreciation and amortization	(304,236)	(168,523)
Net property and equipment	806,335	556,648
Deferred financing cost	4,382	4,801
TOTAL ASSETS	$ 1,038,946	$ 590,118
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 41,462	$ 36,967
Accrued liabilities	52,928	32,565
Deferred tax liability current	18,931	
Income taxes payable	1,383	
Fair value of interest rate derivatives	1,187	384
Accrued abandonment costs	2,554	312
Deferred revenue		12,500
Total current liabilities	118,445	82,728
LONG-TERM DEBT	250,000	215,500
Accrued abandonment costs	11,250	5,868
Deferred income tax liability	7,988	
Fair value of interest rate derivatives	617	
Fair value of oil and gas derivatives		2,407
Total liabilities	388,300	306,503

Commitments and contingencies (See Note 10)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized:		
Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000	2,250	2,250
Common stock: $0.20 par value, 100,000,000 and 50,000,000 shares authorized, respectively; issued and outstanding 37,562,659 and 34,821,317 shares, respectively	7,188	6,340
Treasury stock (9,793 and 16,359 shares, respectively)	(293)	(422)
Additional paid in capital	576,961	341,098
Retained earnings (accumulated deficit)	64,540	(65,651)
Total stockholders equity	650,646	283,615
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 1,038,946	$ 590,118

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, 2008	2007	2006
REVENUES:			
Oil and gas revenues	$ 215,369	$ 110,691	$ 73,933
Other	682	614	838
	216,051	111,305	74,771
OPERATING EXPENSES:			
Lease operating expense	31,950	22,465	12,688
Production and other taxes	7,542	2,272	3,345
Transportation	8,645	5,964	3,791
Depreciation, depletion and amortization	107,123	79,766	37,225
Exploration	8,404	7,346	5,888
Impairment of oil and gas properties	28,582	7,696	9,886
General and administrative	24,254	20,888	17,223
Gain on sale of assets	(145,876)	(42)	(23)
Other		109	
	70,624	146,464	90,023
Operating income (loss)	145,427	(35,159)	(15,252)
OTHER INCOME (EXPENSE):			
Interest expense	(15,862)	(11,870)	(7,845)
Interest income	2,184		
Gain (loss) on derivatives not designated as hedges	51,547	(6,439)	38,128
Loss on early extinguishment of debt			(612)
	37,869	(18,309)	29,671
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	183,296	(53,468)	14,419
INCOME TAX EXPENSE	(46,556)	(3,034)	(5,120)
INCOME (LOSS) FROM CONTINUING OPERATIONS	136,740	(56,502)	9,299
DISCONTINUED OPERATIONS			
Gain on sale of assets, net of tax (See Note 12)	29	9,662	
Income (loss) on discontinued operations, net of tax (See Note 9)	(531)	1,807	(7,660)
	(502)	11,469	(7,660)
NET INCOME (LOSS)	136,238	(45,033)	1,639

PREFERRED STOCK DIVIDENDS	6,047	6,047	6,016
PREFERRED STOCK REDEMPTION PREMIUM			1,545
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 130,191	$ (51,080)	$ (5,922)
NET INCOME (LOSS) PER COMMON SHARE-BASIC			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 4.04	$ (2.21)	$ 0.37
DISCONTINUED OPERATIONS	$ (0.01)	$ 0.45	$ (0.30)
NET INCOME (LOSS)	$ 4.03	$ (1.76)	$ 0.07
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 3.85	$ (2.00)	$ (0.24)
NET INCOME (LOSS) PER COMMON SHARE DILUTED			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 3.49	$ (2.21)	$ 0.37
DISCONTINUED OPERATIONS	$ (0.01)	$ 0.45	$ (0.31)
NET INCOME (LOSS)	$ 3.48	$ (1.76)	$ 0.06
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 3.48	$ (2.00)	$ (0.24)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING BASIC	33,806	25,578	24,948
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING DILUTED	40,397	25,578	25,412

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,		
	2008	**2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 136,238	$ (45,033)	$ 1,639
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	107,123	79,766	52,642
Unrealized (gain) loss on derivatives not qualifying for hedge accounting	(53,995)	16,079	(40,185)
Deferred income taxes	26,919	9,025	904
Dry hole costs	312	939	7,926
Amortization of leasehold costs	5,838	6,211	5,488
Impairment of oil and gas properties	29,751	9,223	24,790
Stock based compensation (non-cash)	5,493	5,282	5,962
Gain on sale of assets	(145,876)	(14,792)	(23)
Loss on early extinguishment of debt			612
Other non-cash items	1,970	1,370	476
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	1,467	1,105	(3,268)
Deferred revenue	(12,500)	12,500	
Accrued oil and gas revenue	(3,395)	(1,511)	1,174
Accounts payable	4,495	5,022	4,689
Income taxes payable	1,383		
Accrued liabilities	3,184	409	2,838
Prepaid expenses and other	(1,368)	330	(531)
Net cash provided by operating activities	107,039	85,925	65,133
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(362,847)	(291,486)	(261,435)
Proceeds from sale of assets	175,061	72,293	2,698
Net cash used in investing activities	(187,786)	(219,193)	(258,737)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of bank borrowings	(155,500)	(173,000)	(184,500)
Proceeds from bank borrowings	190,000	187,000	181,000
Net proceeds from common stock offering	191,340	123,815	
Excess tax benefit from stock based compensation	3,222		
Exercise of stock options and warrants	2,819	203	406
Deferred financing costs	(1,498)	(439)	(5,598)
Preferred stock dividends	(6,047)	(6,047)	(6,016)
Proceeds from convertible note offering			175,000
Net proceeds from preferred stock offering			28,973
Redemption of preferred stock			(9,319)
Other	(489)		

Net cash provided by financing activities	223,847	131,532	179,946
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	143,100	(1,736)	(13,658)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	4,448	6,184	19,842
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 147,548	$ 4,448	$ 6,184
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
CASH PAID DURING THE YEAR FOR INTEREST	$ 12,981	$ 10,178	$ 7,284
CASH PAID DURING THE YEAR FOR INCOME TAXES	$ 14,778	$	$

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In Thousands)

	2008		2007		2006	
	Shares	Amount	Shares	Amount	Shares	Amount
Series A Preferred Stock						
Balance, beginning of year		$		$	792	$ 792
Offering of preferred stock					(792)	(792)
Balance, end of year		$		$		$
Series B Preferred Stock						
Balance, beginning of year	2,250	$ 2,250	2,250	$ 2,250	1,650	$ 1,650
Issuance of preferred stock					600	600
Balance, end of year	2,250	$ 2,250	2,250	$ 2,250	2,250	$ 2,250
Common Stock						
Balance, beginning of year	34,821	$ 6,340	28,218	$ 5,049	24,805	$ 4,961
Offering of common stock	4,030	806	6,431	1,286		
Issuance of and amortization of restricted stock	53	11	108	(8)	182	36
Exercise of stock options and warrants	141	28	57	12	66	44
Director stock grants	16	3	7	1	37	7
Shares pursuant to share lending agreement	(1,498)				3,122	
Redemption of Series A preferred stock					6	1
Balance, end of year	37,563	$ 7,188	34,821	$ 6,340	28,218	$ 5,049
Treasury Stock						
Balance, beginning of year	16	$ (422)		$		$
Purchases	16	(485)	40	(1,231)		
Retirements	(22)	614	(24)	809		
Balance, end of year	10	$ (293)	16	$ (422)		$
Additional Paid in Capital						
Balance, beginning of year		$ 341,098		$ 213,666		$ 187,967
Offering of common stock		224,405		122,529		
Issuance of and amortization of restricted stock		2,686		1,745		2,205
Stock based compensation		2,180		2,727		2,487
Excess tax benefit from stock based compensation		3,222				
Exercise of stock options and warrants		2,791		192		295
Director stock grants		579		239		1,388
Offering of preferred stock						28,373
Redemption of Series A preferred stock						(6,983)
Reclassification from unamortized restricted stock upon adoption of FAS 123R						(2,066)
Balance, end of year		$ 576,961		$ 341,098		$ 213,666
Retained Earnings (Accumulated Deficit)						

Balance, beginning of year	(65,651)	(14,571)	(8,649)
Net income (loss)	136,238	(45,033)	1,639
Preferred stock dividend	(6,047)	(6,047)	(6,016)
Redemption of Series A preferred stock			(1,545)
Balance, end of year	$ 64,540	$ (65,651)	$ (14,571)
Unamortized Restricted Stock Awards			
Balance, beginning of year	$	$	$ (2,066)
Reclassification to APIC upon adoption of FAS 123R			2,066
Balance, end of year	$	$	$
Accumulated Other Comprehensive Loss			
Balance, beginning of year	$	$ (1,261)	$ (3,066)
Other comprehensive loss		1,261	1,805
Balance, end of year	$	$	$ (1,261)
Total Stockholders Equity at December 31	$ 650,646	$ 283,615	$ 205,133

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, 2008	2007	2006
Net income (loss)	$ 136,238	$ (45,033)	$ 1,639
Other comprehensive income (loss):			
Change in fair value of derivatives (1)			(1,025)
Reclassification adjustment (2)		1,261	2,830
Other comprehensive income (loss)		1,261	1,805
Comprehensive income (loss)	$ 136,238	$ (43,772)	$ 3,444
(1) Net of income tax benefit of:	$	$	$ 552
(2) Net of income tax expense of:	$	$ 679	$ 1,524

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, 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.

Presentation Change The Consolidated Statement of Operations include a category of expense titled Production and other taxes which is a change from Production taxes in prior period presentations. The changed category includes ad valorem taxes as well as production taxes for which all comparative periods presented have been adjusted.

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. As of December 31, 2008, we held short term investments in money market funds with three institutions meeting our short term investment policy criteria. As of December 31, 2008, short term investments totaled $136.5 million and carried maturities of fourteen days or less and are considered cash equivalents. We continue to monitor these institutions in light of the current financial market crisis and in accordance with our policy.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Many of our receivables are from a limited number of purchasers. Accordingly, accounts receivable from such purchases could be significant. Generally, our natural gas and crude oil receivables are collected within 30-60 days of production. We also have receivables from joint interest owners of properties we operate. We may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of December 31, 2008 and 2007, our allowance for doubtful accounts was immaterial.

Assets Held for Sale Assets Held for Sale as of December 31, 2008, represents our remaining asset in South Louisiana, the Plumb Bob field. Assets held for sale as of December 31, 2007 represent our remaining assets in the St. Gabriel, Bayou Bouillon and Plumb Bob fields.

Property and Equipment We follow the successful efforts method of accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases.

Exploration expenditures, including geological and geophysical costs, delay rentals and exploratory dry hole costs are expensed as incurred. Costs of drilling exploratory wells are initially capitalized pending determination

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of whether proved reserves can be attributed to the discovery. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are expensed. Development costs are capitalized, including the costs of unsuccessful development wells.

Proved oil and gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying amounts may not be recoverable. In performing this review, future net cash flows are calculated based on estimated future oil and gas sales revenues less future expenditures necessary to develop and produce the reserves. If the sum of these estimated future cash flows (undiscounted) is less than the carrying amount of the property, an impairment loss is recognized for the excess of the property s carrying amount over its estimated fair value based on estimated discounted future cash flows. We perform this comparison using our estimates of future commodity prices and proved and probable reserves. For the years ended December 31, 2008, 2007 and 2006, we recorded impairments on continuing operations of $28.6 million, $7.7 million and $9.9 million, respectively.

Depreciation and depletion of producing oil and gas properties is calculated using the units-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 capitalized asset retirement costs 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.

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 three to five years.

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.

Revenue Recognition Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. 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, 2008, 2007 and 2006, the net assets for gas balancing were less than $0.1 million, $1.2 million and $1.5 million, respectively. Differences between actual production and net working interest volumes are routinely adjusted.

Derivative Instruments and Hedging Activities We use 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*

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. SFAS 133 also requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Fair Value Measurement We adopted SFAS No. 157, *Fair Value Measurements* (SFAS 157) effective January 1, 2008 on a prospective basis. This statement defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. Under SFAS 157, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As of January 1, 2008, SFAS 157 was effective for all financial assets and liabilities subject to its provisions and certain nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a recurring basis. Our derivative instruments are carried at fair value and are therefore subject to the provisions of SFAS 157. In accordance with SFAS 157, we measure the fair value of our derivative instruments by applying the income approach, using inputs that are derived principally from observable market data. The adoption of SFAS 157 did not have a material impact on our financial statements. See Note 13.

Income Taxes We follow the provisions of SFAS No. 109, *Accounting for Income Taxes*, (SFAS 109) as clarified by the Financial Accounting Standard Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), 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. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

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 calculated using the Treasury Stock method.

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

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

significant. Revenues from three purchasers accounted for 33%, 20% and 9% of oil and gas revenues for the year ended December 31, 2008. Revenues from three purchasers accounted for 31%, 23% and 10% of oil and gas revenues for the year ended December 31, 2007. Revenues from two purchasers accounted for 35% and 15% of oil and gas revenues for the year ended December 31, 2006.

Share-Based Compensation Plan We account for our stock based compensation in accordance with SFAS No. 123 (revised 2004), *Share-Based Paymen*t (SFAS 123R). 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 FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159). SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 is effective as of the beginning of an entity s first fiscal year beginning after November 15, 2007. We adopted SFAS 159 as of January 1, 2008. Adoption had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

In December 2007, the FASB issued SFAS 141(R), *Business Combinations* (SFAS 141(R)). This statement requires most identifiable assets, liabilities and noncontrolling interests acquired in a business combination (as defined in the statement) to be recorded at fair value on the acquisition date. This statement is effective for periods beginning on or after December 15, 2008, and earlier adoption is prohibited. SFAS 141(R) will be applied prospectively to business combinations occurring after January 1, 2009.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* (SFAS 161). SFAS 161 amends and expands the disclosure requirements of SFAS No. 133 by requiring enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 will be effective as of January 1, 2009. As SFAS 161 provides only disclosure requirements, the adoption of this standard will not have an impact on our results of operations, cash flows or financial positions.

On May 9, 2008, the FASB issued FASB Staff Position Accounting Principles Board (APB) 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)* (the FSP). The FSP requires the issuer of certain convertible debt instruments that may be settled in cash on conversion to separately account for the liability and equity components in a manner that reflects the issuer s nonconvertible debt borrowing rate. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The effective date of the FSP is for financial statements issued for fiscal years beginning after December 15, 2008. The FSP does not permit earlier application, however does require retrospective application to all periods presented in the

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial statements (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). Our $175 million 3.25% convertible senior notes due 2026 (see Note 4) is affected by this new standard. Accordingly, we will adopt the standard as of January 1, 2009 and will first reflect the application within the first quarter 2009 financial statements. We will record in the first quarter 2009 a debt discount of $23.3 million which will be amortized using the effective interest rate method based upon a 5 year term. Our comparative financial statements will reflect additional interest expense of $0.5 million in 2006, $6.2 million in 2007 and $6.8 million in 2008 as a result of the retrospective requirement.

In December 2008, the Securities and Exchange Commission (SEC) issued a final rule adopting revisions to its oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive information related to the determination and disclosure of oil and gas reserves information. The provisions of this final rule are effective for fiscal years ending on or after December 31, 2009. We are currently assessing the impact that this final rule will have on our financial statements.

NOTE 2 Share-Based Compensation Plans

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan), at our annual meeting of stockholders. The 2006 Plan replaces our previously adopted Goodrich Petroleum Corporation 1995 Stock Option Plan and 1997 Non-Employee Directors Stock Option Plan.

The 2006 Plan is intended to promote the interests of the Company, by providing a means by which Employees, Consultants and Directors may acquire or increase their equity interest in the Company and may develop a sense of proprietorship and personal involvement in the development and financial success of the Company, and to encourage them to remain with and devote their best efforts to the business of the Company, thereby advancing the interests of the Company and its stockholders. The Plan is also contemplated to enhance the ability of the Company and its Subsidiaries to attract and retain the services of individuals who are essential for the growth and profitability of the Company.

The 2006 Plan provides that the Compensation Committee shall have the authority to determine the Participants to whom stock options, restricted stock, performance awards, phantom shares and Stock Appreciation Rights may be granted. The 2006 Plan also provides for grants to non-employee directors.

No further awards will be granted under the previously adopted plans, however, those plans shall continue to apply to and govern awards made thereunder. Under the 2006 Plan, a maximum of 2.0 million new shares are reserved for issuance as awards of share options to officers, employees and non-employee directors. As of December 31, 2008, a total of 1,196,096 shares were available for future grants under the 2006 Plan.

Stock Options

The 2006 Plan provides that the option price of shares issued be equal to the market price on the date of grant. With the exception of option grants to non-employee directors which vest immediately, options vest ratably on the anniversary of the date of grant over a period of time, typically three years. All options expire ten years after the date of grant.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Option activity under our stock option plans as of December 31, 2008, and changes during the 12 months then ended were as follows:

	Shares	Weighted Average Exercise Price	Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2008	949,333	$ 20.95		
Granted	162,000	21.59		
Exercised	(141,200)	19.97		$ 6,191
Forfeited				
Outstanding at December 31, 2008	970,133	$ 21.20	6.45	$ 8,488
Exercisable at December 31, 2008	630,800	$ 20.25	6.37	$ 6,118

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 2008 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, 2008. 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, 2008, 2007, and 2006 was $6.2 million, $1.8 million and $1.7 million, respectively.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2008	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2008	Weighted Average Exercise Price
$2.63 to $5.85	24,000	2.21	$ 3.97	24,000	$ 3.97
$16.46 and $19.78	307,300	6.11	18.08	307,300	18.08
$21.59 to $27.81	638,833	6.77	23.35	299,500	23.78
	970,133	6.45	$ 21.20	630,800	$ 20.25

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 per share weighted average fair value of stock options granted during the years ended December 31, 2008 and 2006, were $10.72 and $12.98, respectively, on the date of grant. There were no options granted in 2007.

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The estimated fair value of the options granted during 2008, 2006 and prior years was calculated using a Black-Scholes Merton option pricing model (Black Scholes). There were no options granted in 2007. The following schedule reflects the various assumptions included in this model as it relates to the valuation of our options:

	2008	2006
Risk free interest rate	3.52%	4.50-4.97%
Weighted average volatility	53%	54-57%
Dividend yield	0%	0%
Expected years until exercise	5	5-6

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.

As of December 31, 2008, $3.6 million of total unrecognized compensation cost related stock options is expected to be recognized over a weighted average period of approximately 3.8 years.

Restricted Stock

In 2003, we commenced granting a series of restricted share awards. Restricted shares awarded under the 2006 Plan typically have a vesting period of three years. During the vesting period, ownership of the shares cannot be transferred and the shares are subject to forfeiture if employment ends before the end of the vesting period. Certain restricted stock awards provide for accelerated vesting. Restricted shares are not considered to be currently issued and outstanding. The fair value of the awards of restricted shares, determined as the market value of the shares at the date of grant, is expensed ratably over the vesting period.

The January 1, 2006, balance of unamortized restricted stock awards of $2.1 million was reclassified against additional paid-in-capital upon adoption of SFAS 123R. For all periods after January 1, 2006, common stock par value will be recorded when the restricted (phantom) 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.

During 2008, 2007 and 2006, we granted 437,048, 13,000 and 215,629 shares of our common stock, under the plan, valued at $11.4 million, $0.4 million and $7.1 million, respectively at the time of issuance. During 2008, 2007 and 2006, $3.3 million, $2.6 million and $2.1 million, respectively, were charged to compensation expense related to the restricted share awards. The fair value of restricted stock vested during 2008, 2007, and 2006 were $2.1 million, $4.5 million and $1.4 million, respectively.

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Restricted stock activity under our plan as of December 31, 2008, and changes during the year then ended were as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value	Total Value
Unvested at January 1, 2008	108,251	$ 33.60	$ 3,637,508
Vested	(68,347)	30.87	(2,109,849)
Granted	437,048	26.15	11,427,062
Forfeited	(5,866)	30.01	(176,055)
Unvested at December 31, 2008	471,086	$ 27.13	$ 12,778,666

As of December 31, 2008, $11.4 million of total unrecognized compensation cost related to restricted stock is expected to be recognized over a weighted average period of approximately 2.4 years.

Total stock based compensation for the year ended December 31, 2008, of $5.9 million has been recognized as a component of general and administrative expenses in the accompanying Consolidated Financial Statements.

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

	Year Ended December 31,		
	2008	2007	2006
Pretax stock option expense	$ 2,181	$ 2,727	$ 2,487
Pretax restricted stock expense	3,312	2,555	2,092
Pretax director stock expense	440	252	1,383
Total pretax stock based compensation:	$ 5,933	$ 5,534	$ 5,962

NOTE 3 Asset Retirement Obligations

We apply SFAS No. 143 which requires us to record the fair value of a liability associated with the retirement obligations of our tangible long-lived assets in the periods in which it is incurred. We capitalize the discounted fair value of the liability when initially incurred. The liability is accreted through accretion expense to its full fair value over the life of the long-lived asset. Accretion expense is included in Depreciation, depletion and amortization on our Consolidated Statement of Operations.

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The reconciliation of the beginning and ending asset retirement obligation for the periods ending December 31, 2008 and 2007, is as follows (in thousands):

	December 31, 2008	December 31, 2007
Beginning balance	$ 6,180	$ 9,557
Liabilities incurred	2,305	2,710
Revisions in estimated liabilities	5,063	
Liabilities settled		(41)
Accretion expense	331	221
Dispositions	(75)	(6,267)
Ending balance	$ 13,804	$ 6,180
Current liability	$ 2,554	$ 312
Long term liability	$ 11,250	$ 5,868

During 2008, we determined that the costs of restoring well site locations and to a lesser extent the plug and abandonment of well bores had significantly increased. Due to these increases, we revised our previously estimated asset retirement obligation by a discounted $5.1 million. We expect accretion expense to increase in future periods. The Dispositions for 2007 represents the Asset Retirement Obligation for substantially all of our properties in South Louisiana sold to a private company. The ending balance at December 31, 2008 and 2007 includes $1.4 million and $0.3 million, respectively, for Assets Held for Sale. See Note 9.

NOTE 4 Long-Term Debt

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

	December 31, 2008	December 31, 2007
Senior Credit Facility	$	$ 40,500
Second Lien Term Loan	75,000	
3.25% Convertible Senior notes due 2026	175,000	175,000
Total long-term debt	$ 250,000	$ 215,500

Senior Credit Facility

In 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (as amended, the Senior Credit Facility) and a term loan that expanded our borrowing capabilities. Total lender commitments under the Senior Credit Facility were $200 million, and the Senior Credit Facility matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of the borrowing base. We paid off the total amount outstanding under the Senior Credit Facility in July, 2008 with proceeds from our equity offering. Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.00% to 0.75%, or LIBOR plus 1.25% to 2.25%, depending on borrowing base utilization. At December 31, 2008, we had a borrowing base of $175.0 million and no amounts outstanding under the Senior Credit Facility. Pursuant to the terms of our Senior Credit Facility, the next redetermination of our borrowing base will be March 31, 2009.

Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

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The terms of the Senior Credit Facility, as amended, require us to maintain certain covenants. Capitalized terms used, but not defined, here have the meanings assigned to them in the Senior Credit Facility. As of December 31, 2008 we were in compliance with all of the financial covenants of our Senior Credit Facility. The covenants in effect at December 31, 2008 include:

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio of not less than 3.0/1.0 for the trailing four quarters;
- Total Debt no greater than 3.0 times EBITDAX for the trailing four quarters (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. The 3.25% convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio.); and
- Asset coverage ratio (defined as the present value of proved reserves discounted at 10% divided by total debt, excludes 3.25% convertible senior notes) of not less than 1.5 to 1.0.

Second Lien Term Loan

On January 16, 2008, we entered into a new Second Lien Term Loan Agreement which provides for a 3-year, secured, non-revolving loan of $75.0 million and is due in a single maturity on December 31, 2010. We have no rights to prepay in the first year. Voluntary prepayment rights in the second year are at 101% of par, and thereafter at par. Interest on the Second Lien Term Loan accrues at a rate of LIBOR plus 550 basis points and is payable quarterly in arrears. As of December 31, 2008, we were in compliance with all of the financial covenants of our Second Lien Term Loan. The terms of the Second Lien Term Loan Agreement contain financial covenants which include:

- Asset coverage ratio (defined as the present value of proved reserves discounted 10% to total debt, excludes 3.25% convertible senior notes) of not less than 1.5 to 1.0;
- Total debt to EBITDAX ratio of not more than 3.0 to 1.0 (total debt to exclude the 3.25% convertible senior notes); and
- EBITDAX to interest expense ratio of not less than 3.0 to 1.0.

Convertible Senior Notes

In December 2006, we sold $175.0 million of 3.25% convertible senior notes (the notes) due in December 2026. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes are our senior unsecured obligations and 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 interest is paid semi-annually on June 1 and December 1. Interest payments on the notes began on June 1, 2007.

Before December 1, 2011, we may not redeem the notes. On or after December 11, 2011, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of December 11, 2011, 2016 and 2021. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares. 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

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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.

NOTE 5 Net Income (Loss) Per Common Share

Net income (loss) applicable to common stock was used as the numerator in computing basic and diluted income (loss) per common share for the years ended December 31, 2008, 2007 and 2006. The following table sets forth information related to the computations of basic and diluted income (loss) per share.

	Year Ended December 31, 2008	2007	2006
	(Amounts in thousands, except per share data)		
Basic income (loss) per share:			
Income (loss) applicable to common stock	$ 130,191	$ (51,080)	$ (5,922)
Average shares of common stock outstanding (1)	33,806	25,578	24,948
Basic income (loss) per share	$ 3.85	$ (2.00)	$ (0.24)
Diluted income (loss) per share:			
Income (loss) applicable to common stock	$ 130,191	$ (51,080)	$ (5,922)
Dividends on convertible preferred stock (2)	6,047		
Interest and amortization of loan cost on senior convertible notes, net of tax (3)	4,385		
Diluted income (loss)	$ 140,623	$ (51,080)	$ (5,922)
Average shares of common stock outstanding (1)	33,806	25,578	24,948
Assumed conversion of convertible preferred stock (2)	3,588		
Assumed conversion of convertible senior notes (3)	2,654		
Stock options, warrants and restricted stock (4)	349		
Average diluted shares outstanding	40,397	25,578	24,948
Diluted income (loss) per share	$ 3.48	$ (2.00)	$ (0.24)

(1) This amount does not include 1,624,300 shares in 2008 and 3,122,263 shares each in 2006 and 2007 of common stock outstanding under the Share Lending Agreement. See Note 7.

(2)

Common shares issuable upon assumed conversion of our convertible preferred stock amounting to 3,587,850 shares and the accrued dividends on the preferred stock were not included in the computation of diluted loss per share for 2006 and 2007 as they would have not been dilutive.

(3) Common shares issuable upon assumed conversion of our convertible senior notes amounting to 2,653,927 shares and the accrued interest on the senior notes were not included in the computation of diluted loss per share for the periods presented in 2006 and 2007 as they would have not been dilutive.

(4) Common shares on assumed conversion of restricted stock and employee stock option stock in the amounts of 463,173 and 210,180 shares for the years 2006 and 2007 respectively, were not included in the computation of diluted loss per common share since their inclusion would have not been dilutive.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 6 Income Taxes

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

	Year Ended December 31, 2008	2007	2006
Current:			
Federal	$ (5,331)	$ (97)	$
State	(10,813)		
	(16,144)	(97)	
Deferred:			
Federal	(29,276)	(9,025)	(904)
State	(866)		
	(30,142)	(9,025)	(904)
Total	$ (46,286)	$ (9,122)	$ (904)

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, 2008	2007	2006
Income tax (expense) benefit from continuing operations			
Tax at U.S. statutory income tax	$ (64,153)	$ 18,713	$ (5,106)
Valuation allowance	25,476	(21,688)	
State income taxes-net of federal benefit	(7,895)		
Nondeductible expenses and other	16	(59)	(14)
	(46,556)	(3,034)	(5,120)
Income tax (expense) benefit from discontinued operations			
Tax at U.S. statutory income tax	270	(6,088)	4,216
	270	(6,088)	4,216

Total tax expense	$ (46,286)	$ (9,122)	$ (904)

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The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are presented below (in thousands):

	December 31, 2008	December 31, 2007
Current deferred tax liabilities:		
Derivative financial instruments	$ (18,931)	
Total current deferred tax liabilities	(18,931)	
Noncurrent deferred tax assets:		
Operating loss carryforwards	$ 2,627	$ 18,725
Statutory depletion carryforward	7,034	7,034
AMT tax credit carryforward	6,854	1,523
Derivative financial instruments	216	184
Compensation	2,403	2,075
Contingent liabilities and other	1,004	4,906
Total gross noncurrent deferred tax assets	20,138	34,447
Less valuation allowance	(7,486)	(32,961)
Net noncurrent deferred tax assets	12,652	1,486
Noncurrent deferred tax liabilities:		
Property and equipment	(17,680)	(126)
Bond discount	(2,960)	(1,360)
Total noncurrent deferred tax liabilities	(20,640)	(1,486)
Net noncurrrent deferred tax asset (liability)	$ (7,988)	$

The valuation allowance for deferred tax assets decreased by $25.5 million in 2008. This decrease was primarily due to a significant gain on sale of assets recognized in the third quarter. As a result of this gain on sale, we believe that we will be in a position to utilize the majority of our net operating loss carryforwards when we file our 2008 tax return. We believe it is now more likely than not that we will be able to recognize our deferred tax assets associated with these net operating loss carry forwards and have therefore released the previously booked valuation allowance.

As of December 31, 2008, we have net operating loss carryforwards of approximately $9.8 million for tax purposes which will expire in 2026. The Company also has a minimum tax credit carryforward of $6.9 million which will not begin to be used until after the available NOLs have been used or expired and when regular tax exceeds the current year alternative minimum tax.

Our stock based deferred compensation plans have generated $11.5 million of additional tax deductions through 2008. The Company realized $9.2 million ($3.2 million, net of tax) of these deductions in 2008 and the associated tax benefit was recorded as additional paid in capital. The remaining tax deductions are not currently recognized as a component of our deferred tax asset. They will be recognized when the net operating loss carryforward is utilized to offset future taxable income.

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 $0.6 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 $1.0 million. In order to avoid future penalties and interest, the Company

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

paid, under protest, $1.0 million to the State of Louisiana in April 2007 which payment was expensed in general and administrative expense in first quarter 2007. We plan to pursue the reimbursement of the full $1.0 million paid under protest. Should our efforts prevail, the taxes paid under protest would be refunded, at which time we would book a credit to general and administrative expense.

The amount of unrecognized tax benefits did not materially change as of December 31, 2008. The amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or our financial position. We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. Federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 1992.

Our continuing practice is to recognize estimated interest and penalties related to potential underpayment on any unrecognized tax benefits as a component of income tax expense in the Consolidated Statement of Operations. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations before December 31, 2009.

NOTE 7 Stockholders Equity

Caddo Parish Acquisition for Common Stock

In May 2008, we acquired approximately 3,665 net acres in the Longwood field of Caddo Parish, Louisiana, through the issuance of 908,098 shares of our common stock valued at approximately $33.9 million. See Note 12.

Equity Offering

On July 14, 2008, we closed the public offering of 3,121,300 shares of our common stock at a price of $64.00 per share. Net proceeds from the offering were approximately $191.3 million after deducting the underwriters discount and estimated offering expenses. We used approximately $96.0 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility. We used the remaining net proceeds for general corporate purposes, including the funding of a portion of our 2008 drilling program, other capital expenditures and working capital requirements.

Share Lending Agreement

In connection with the offering of our 3.25% notes in December 2006, we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock 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 the common stock offerings and lending transactions under this agreement. 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 the notes to shares of our common stock pursuant to the terms of the indenture governing the notes.

The Share Lending Agreement also requires BSC to post collateral if its credit rating is below either A3 by Moody s Investors Service (Moody s) or A- by Standard and Poor s (S&P). As a result of the long term ratings downgrade of BSC in March 2008, BSC was required to return all or a portion of the borrowed shares or collateralize the return obligation with cash or highly liquid non-cash collateral. On March 20, 2008, BSC had returned 1,497,963 shares of the 3,122,263 originally borrowed shares and fully collateralized the remaining 1,624,300 borrowed shares with a cash collateral deposit of approximately $41.3 million. This amount represents the market value of the remaining borrowed shares at March 20, 2008. Under certain conditions, BSC is required

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to maintain collateral value in the amount at least equal to the market value of the outstanding borrowed shares. The 1,497,963 shares returned to us were recorded as treasury stock and retired in March 2008.

In May 2008, JP Morgan Chase & Co. completed its acquisition of and assumed all counterparty liabilities of The Bear Stearns Companies Inc. JP Morgan Chase & Co. s credit rating exceeds that required by the Share Lending Agreement. Thus, collateral is no longer required.

The 1,624,300 shares of common stock outstanding as of December 31, 2008, under the Share Lending Agreement are required to be returned to us in the future. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. As a result, the shares of common stock lent under the Share Lending Agreement have no impact on the earnings per share calculation.

Capped Call Option Transactions

On December 10, 2007, we closed the public offering of 6,430,750 shares of our common stock at a price of $23.50 per share. Net proceeds from the offering were approximately $145.4 million after deducting the underwriters discount and estimated offering expenses. We used approximately $123.8 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility, and approximately $21.6 million of the net proceeds to purchase capped call options on shares of our common stock from affiliates of BSC and J.P. Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. One third of the options will expire over each of three separate multi-day settlement periods beginning approximately 18 months, 24 months and 30 months from the closing of the offering, respectively.

The capped call option transactions are expected to result in our receipt, on a net share, cashless basis of a certain number of shares of our common stock if the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for the relevant tranche is greater than the lower call strike price of the capped call option transactions. We refer to the amount by which the market value per share exceeds the lower call strike price as an in-the-money amount for the relevant tranche of the capped call option transaction. The in-the-money amount will never exceed the difference between the upper call strike price and the lower call strike price (i.e., it will be capped). The lower call strike price is $23.50, which corresponds to the price to the public in the equity offering and the upper call strike price is $32.90, which corresponds to 140% of the price to the public in the offering. Both lower and upper call strike prices are subject to customary anti-dilution and certain other adjustments. The number of shares of our common stock that we will receive from the option counterparties upon expiration of each tranche of the capped call option transactions will be equal to the in-the-money amount of that tranche divided by the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for that tranche. If the stock price is equal to the upper call strike price of $32.90 on each of the settlement dates, we will recoup up to 1.6 million shares.

The capped call option agreements were separate transactions entered into by us with the option counterparties and were not part of the terms of the offering of common stock.

The capped call option agreements require an option counterparty to transfer their rights and obligations within 30 days if their credit rating is below either Baa1 by Moody s or BBB+ by S&P. As a result of the ratings downgrade of BSC on March 14, 2008, BSC was obligated to transfer their rights and obligations under the capped call option agreement to a suitable counterparty (one with a credit rating of at least BBB+ by S&P and Baa1 by Moody s) within 30 days. BSC s obligation to transfer its rights and obligations to an entity with a higher credit rating was cured by a ratings upgrade on March 24, 2008.

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During the second quarter of 2008, BSC sold its position in the capped call options to Bank of America.

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.

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.

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 before 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.

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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.

NOTE 8 Derivative Activities

Commodity Derivative Activity

We enter into swap contracts, costless collars or other derivative agreements from time to time to manage the commodity price risk for a portion of our production. Our strategy, which is administered by the Hedging Committee of our Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our estimated total production for the period the derivatives are in effect. As of December 31, 2008, the commodity derivatives we used were in the form of:

(a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX and field prices,

(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; and

We account for our commodity derivative contracts in accordance with SFAS 133, which requires each derivative to be recorded on the balance sheet as an asset or liability at its fair value. Additionally, the statement requires that changes in a derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is executed. Currently, none of our commodity derivative contracts are being accounting for as hedges and as such, all changes in the fair value of these instruments are recognized in earnings.

As of December 31, 2008, our open forward positions on our outstanding commodity hedging contracts, all of which were with either BNP or Bank of Montreal, was as follows:

Collars (NYMEX)	Daily Volume	Total Volume	Floor/Cap Average Price		Fair Value at December 31, 2008
Natural gas (MMBtu)					$ 19,396,126
1Q 2009	20,000	1,800,000	$ 8.75	$13.10	
2Q 2009	20,000	1,820,000	$ 8.75	$13.10	

3Q 2009	20,000	1,840,000	$ 8.75	$13.10	
4Q 2009	20,000	1,840,000	$ 8.75	$13.10	
Swaps (NYMEX)			**Average Price**		
Natural gas (MMBtu)					19,773,709
1Q 2009	20,000	1,800,000	$8.83		
2Q 2009	20,000	1,820,000	$8.83		
3Q 2009	20,000	1,840,000	$8.83		
4Q 2009	20,000	1,840,000	$8.83		
Swaps (TexOk)			**Field Price (1)**		
Natural gas (MMBtu)					16,106,471
1Q 2009	20,000	1,800,000	$7.87		
2Q 2009	20,000	1,820,000	$7.87		
3Q 2009	20,000	1,840,000	$7.87		
4Q 2009	20,000	1,840,000	$7.87		
			Total	$	55,276,306

(1) The index price is based upon Natural Gas Pipeline of America. TexOK (NGPLTXOK) zone as published in the Inside FERC. The comparable index price based on NYMEX was approximately $8.25/Mmbtu.

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For the year ended December 31, 2008 we recognized a gain of $53.6 million from natural gas derivatives made up of an unrealized gain of $55.4 million offset by a realized loss of $1.8 million.

We have entered into the following contracts subsequent to December 31, 2008:

(a) A NGPLTXOK priced basis swap contract with the Bank of Montreal for 20,000 Mmbtu per day for the months of March through December 2009, locking in a fixed basis to the Company of $0.52 per Mmbtu, and

(b) A NGPLTXOK priced basis swap contract with BNP for 20,000 Mmbtu per day for the months of March through December 2009 locking in a fixed basis to the Company of $0.52 per Mmbtu.

Interest Rate Swaps

We have several variable-rate debt obligations that expose us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. We have not designated our interest rate swaps as hedges under FAS 133. At December 31, 2008, we had the following interest rate swaps in place with BNP Paribas and Bank of Montreal.

Effective Date	Maturity Date	LIBOR Swap Rate	Notional Amount (Millions)	Fair Value (Dollars)
2/26/2007	2/26/2009	4.860%	$ 40.0	$ (271,029)
4/22/2008	4/22/2010	3.191%	25.0	(515,584)
4/22/2008	4/22/2010	3.191%	50.0	(1,017,416)
				$ (1,804,029)

For the year ended December 31, 2008, we recognized a $2.1 million loss from the interest rate swaps, of which $1.4 million was unrealized.

NOTE 9 Discontinued Operations

On March 20, 2007, we closed the sale of substantially all of our oil and gas properties in South Louisiana with the exception of the St. Gabriel, Bayou Bouillon and Plumb Bob fields as discussed under Note 1 Assets Held for Sale. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the results of operations for the properties that were sold and for the properties that are held for sale have been reflected as discontinued operations. On August 4, 2008, we closed the sale of our St. Gabriel field and on August 12, 2008 we assigned our interest in the Bayou Bouillon field. See Note 12. We are actively pursuing bids and will accept any reasonable offer on the remaining Plumb Bob field.

The following table summarizes the amounts included in Income (loss) from discontinued operations net of tax (in thousands):

	2008	**2007**	**2006**
Revenues	$ 900	$ 9,470	$ 41,383
Income (loss) from discontinued operations	(817)	2,766	(11,876)
Income tax benefit (expense)	286	(959)	4,216
Income (loss) from discontinued operations, net of tax	(531)	1,807	(7,660)

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NOTE 10 Commitments and Contingencies

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, 2008.

	Payment due by Period					
	Total	2009	2010	2011	2012	2013 and After
Contractual Obligations						
Office space leases	$ 1,699	$ 679	$ 207	$ 213	$ 220	$ 380
Office equipment leases	387	279	79	13	8	8
Drilling contracts	47,672	26,976	8,579	7,665	4,452	
Operational contracts	1,589	699	595	291	4	
Transportation contracts	3,831	1,804	1,926	101		
Total contractual obligations	$ 55,178	$ 30,437	$ 11,386	$ 8,283	$ 4,684	$ 388

Operating Leases We have commitments under an operating lease agreement for office space. Total rent expense for the years ended December 31, 2008, 2007, and 2006, was approximately $0.9 million, $0.8 million and $0.6 million.

Drilling Contracts We have six drilling rigs under contract as of December 31, 2008, four of which are scheduled to expire within 2009.

Litigation We are party to 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

Patrick E. Malloy, III, Chairman of the Board of Directors of our company is a principle of Malloy Energy Company, LLC (MEC). In 2003 and 2004 MEC acquired an approximate 30% working interest in the Bethany Longstreet, Plumb Bob and St. Gabriel fields for which we were the operator. In accordance with industry standard joint operating agreements, we bill MEC for its share of capital and operating cost on a monthly basis. As of December 31, 2008 and 2007, the amounts billed and outstanding to MEC for its share of monthly capital and operating costs were $0.6 million and $1.9 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 after billing and the affiliate is current on payment of its billings.

At the same time we sold a portion of our interests in the Haynesville Shale deep rights at Bethany Longstreet field, MEC consummated a similar transaction for its 30% working interest in the same deep rights with Chesapeake Energy Corporation, or Chesapeake. We and MEC also sold our interest in the St. Gabriel field in August 2008. See Note 12.

We also serve as the operator for a number of other oil and gas wells owned by affiliates of MEC in which we will earn an average working interest of 11% after payout. 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, 2008 and 2007, the amounts billed and outstanding to the affiliate for its

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share of monthly capital and operating costs were both less than $0.1 million at the end of each period 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 after billing and the affiliate is current on payment of its billings.

NOTE 12 Acquisitions and Divestitures

Acquisitions

In February 2008, we acquired additional acreage located in the Angelina River trend for $2.5 million from a private company. We acquired an additional 40% working interest in the James Lime rights in our Bethune area, and an additional 31.25% working interest in the James Lime rights in our Allentown area. After the drilling of the second Allentown well, we earned an additional 6.25% working interest in the James Lime for a total working interest of 93.75%.

In May 2008, we acquired additional interests in the Cotton Valley Trend, which increased our net exposure in the Haynesville Shale. We acquired 3,665 net acres in the Longwood field of Caddo Parish, Louisiana, through the issuance of 908,098 shares of our common stock valued at approximately $33.9 million.

On June 10, 2008, we entered into a definitive agreement with a private company for the right to acquire over time a 50% non-operated interest in 5,800 gross acres (2,900 net) in the Caddo Pine Island field, adjacent to our Longwood field in Caddo Parish, Louisiana. We estimate total consideration to be approximately $3.3 million, which will be comprised of acreage costs for the 50% interest in the leasehold and the cost of a carried interest on the initial well drilled on the acreage.

In two separate transactions in the third quarter of 2008, we purchased a 70% interest in approximately 638 acres of Haynesville Shale formation deep rights in Northwest Louisiana for approximately $6.7 million. Under our joint agreement, we sold 20% of our interest to Chesapeake for $2.6 million in the third quarter 2008. We realized a gain of $0.6 million on the sale.

On August 8, 2008, we announced that we closed on the acquisition of a 50% operated interest in approximately 3,000 gross (1,500 net) acres in northern Nacogdoches County, Texas, approximately five miles southeast of the Trawick field. Purchase price for the acreage, including drilling promote on the initial well, is estimated to be approximately $1.9 million. We have the right to acquire a 50% interest in an additional 3,000 gross (1,500 net) acres through future development for $1,000 per acre, bringing the total potential acreage to approximately 6,000 gross (3,000 net) acres.

Divestitures

On June 16, 2008, we entered into a joint development agreement with Chesapeake to develop our Haynesville Shale acreage in the Bethany Longstreet and Longwood fields of Caddo and DeSoto Parishes, Louisiana. Chesapeake purchased the deep rights to approximately 10,250 net acres of oil and natural gas leasehold comprised of a 20% working interest in approximately 25,000 net acres in the Bethany Longstreet field and a 50% working interest in approximately 10,500 net acres in the Longwood field for $172.6 million. The sale closed on July 15, 2008, resulting in net proceeds of $172.0 million and a gain on the transaction of $145.1 million. Chesapeake also purchased 7,500 net acres of deep rights in the Bethany Longstreet field from a third party, bringing the ownership interest in the deep rights in both fields after closing to 50% each for us and Chesapeake.

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Assets held for sale

In March 2008, we sold seismic data related to the St. Gabriel field for an adjusted price of $0.3 million. The adjusted proceeds of $0.3 million were recorded as a gain. See Note 1.

On August 4, 2008, we closed the sale of our St. Gabriel field to a private party for $0.1 million, resulting in a gain of $0.1 million. This asset was treated as held for sale at December 31, 2007. See Note 1.

On August 12, 2008, we assigned our interest in the Bayou Bouillon field to a private party for a nominal amount. This asset was treated as held for sale at December 31, 2007. We realized a loss of $0.3 million. See Note 1.

NOTE 13 Fair Value Measurements

We adopted SFAS 157 effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS 157 applies to all financial assets and liabilities that are required to be measured and reported on a fair value basis. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for nonfinancial assets and liabilities. For the year ended December 31, 2008, SFAS 157 affects the Company s fair value measurements of its commodity and interest rate derivative positions.

Fair value, as defined in SFAS 157, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether an in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company s credit risk.

Valuation techniques are generally classified into three categories: the market approach; the income approach; and the cost approach. The selection and application of one or more of the techniques requires significant judgment and are primarily dependent upon the characteristics of the asset or liability, the principal (or most advantageous) market in which participants would transact for the asset or liability and the quality and availability of inputs. Inputs to valuation techniques are classified as either observable or unobservable within the following hierarchy:

Level 1 Inputs

These inputs come from quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Inputs

These inputs are other than quoted prices that are observable, for an asset or liability. This includes: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

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Level 3 Inputs

These are unobservable inputs for the asset or liability which require the Company s own assumptions.

As required by SFAS 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. We measure the fair value of our derivative contracts by applying the income approach.

The following table summarizes the valuation and classification of our derivative instruments under SFAS 157 as of December 31, 2008:

	Fair Value Measurement (in thousands)			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Current assets	$	$ 55,276	$	$ 55,276
Current liabilities		(1,187)		(1,187)
Long term liabilities		(617)		(617)
Total	$	$ 53,472	$	$ 53,472

NOTE 14 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 of the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to these short-term maturities of these instruments. We estimate the fair value of our convertible senior notes using quotes from third parties. The carrying amounts and fair values of the other financial instruments and derivatives at December 31, 2008 and 2007, are as follows (in thousands):

	2008		2007	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Senior Credit Facility	$	$	$ 40,500	$ 40,500
Second lien term loan	75,000	75,000		
3.25% Convertible Senior Notes	175,000	132,948	175,000	140,656
Derivative assets (liabilities)				
Gas	55,276	55,276	(139)	(139)
Interest rate	(1,804)	(1,804)	(384)	(384)

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NOTE 15 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, 2008, and 2007 (in thousands):

	2008	2007
Proved properties	$ 1,077,009	$ 716,001
Unproved properties	33,429	25,587
	1,110,438	741,588
Less accumulated depreciation, depletion and amortization	(305,448)	(185,068)
Net oil and gas properties	$ 804,990	$ 556,520

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,		
	2008	2007	2006
Property Acquisition			
Unproved	$ 54,657	$ 10,745	$ 8,569
Proved	7,751		6,120
Exploration	44,765	20,429	12,263
Development (1)	315,030	269,664	244,240
	$ 422,203	$ 300,838	$ 271,192

(1) Includes asset retirement costs of $7.4 million in 2008, $2.7 million in 2007, and $1.3 million in 2006.

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, 2008, 2007 and 2006. 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, 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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The following table sets forth our net proved oil and gas reserves at December 31, 2008, 2007 and 2006 and the changes in net proved oil and gas reserves for the years ended December 31, 2008, 2007 and 2006:

	Natural Gas (MMcf)			Oil (MBbls)		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Proved reserves at beginning of period	346,930	187,012	142,963	1,810	3,201	4,973
Revisions of previous estimates (1)	(62,616)	10,884	(66,409)	(137)	714	(1,612)
Extension and discoveries (2)	126,350	179,959	115,732	470	712	311
Purchases of minerals in place	2,988		7,727	15		3
Sales of minerals in place	(14)	(15,111)		(1)	(2,610)	
Production	(23,189)	(15,814)	(13,001)	(174)	(207)	(474)
Proved reserves at end of period	390,449	346,930	187,012	1,983	1,810	3,201
Proved developed reserves:						
Beginning of period	108,077	76,679	56,700	282	1,862	1,796
End of period	150,174	108,077	76,679	387	282	1,862

	Natural Gas Equivalents (MMcfe)		
	2008	**2007**	**2006**
Proved reserves at beginning of period	357,792	206,217	172,801
Revisions of previous estimates (1)	(63,438)	15,169	(76,081)
Extensions and discoveries (2)	129,170	184,232	117,597
Purchases of minerals in place	3,078		7,745
Sales of minerals in place	(20)	(30,770)	
Production	(24,233)	(17,056)	(15,845)
Proved reserves at end of period	402,349	357,792	206,217
Proved developed reserves:			
Beginning of period	109,769	87,851	67,476
End of period	152,496	109,769	87,851

(1) Revisions of previous estimates were positive in the aggregate in 2007 due to a combination of increased prices from the end of 2006 to the end of 2007 and volume revisions resulting from updated production performance in many of our fields. Alternatively, the revisions of previous estimates in 2006 and 2008 were negative due primarily to significant pricing decreases in both years which caused a number of our proved undeveloped locations in the Cotton Valley area to become uneconomic at those lower price levels.

(2) Extensions and discoveries were positive on an overall basis in all three periods presented, primarily related to our continued drilling activity on existing and newly acquired properties in the Cotton Valley trend of East Texas and North Louisiana.

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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):

	2008	2007	2006
Future revenues	$ 2,052,735	$ 2,399,272	$ 1,190,367
Future lease operating expenses and production taxes	(816,941)	(794,960)	(409,775)
Future development costs (1)	(675,787)	(709,355)	(337,576)
Future income tax expense	(6,907)	(103,186)	(28,764)
Future net cash flows	553,100	791,771	414,252
10% annual discount for estimated timing of cash flows	(385,657)	(507,654)	(213,971)
Standardized measure of discounted future net cash flows	$ 167,443	$ 284,117	$ 200,281
Index price used to calculate reserves (2)			
Natural gas (per Mcf)	$ 5.71	$ 6.80	$ 5.64
Oil (per Bbl)	$ 41.00	$ 92.50	$ 57.75

(1) Includes cumulative asset retirement obligations of $13.8 million, $6.2 million and $9.6 million in 2008, 2007 and 2006, respectively.
(2) These index prices, used to estimate our reserves at these dates, are before deducting or adding 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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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,		
	2008	**2007**	**2006**
Balance, beginning of year	$ 284,117	$ 200,281	$ 410,620
Net changes in prices and production costs related to future production	(68,643)	94,478	(360,635)
Sales and transfers of oil and gas produced, net of production costs	(167,516)	(85,216)	(81,813)
Net change due to revisions in quantity estimates	(81,292)	33,703	(70,212)
Net change due to extensions, discoveries and improved recovery	105,257	178,579	122,144
Net change due to purchases and sales of minerals in place	5,219	(99,628)	8,044
Changes in future development costs	3,426	(48,595)	(44,339)
Previously estimated development cost incurred in period	35,926	15,292	
Net change in income taxes	26,165	(14,660)	142,131
Accretion of discount	31,269	21,419	58,768
Change in production rates (timing) and other	(6,485)	(11,536)	15,573
Net increase (decrease) in standardized measures	(116,674)	83,836	(210,339)
Balance, end of year	$ 167,443	$ 284,117	$ 200,281

NOTE 16 Summarized Quarterly Financial Data (Unaudited)

(In Thousands, Except Per Share Amounts)

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2008					
Revenues	$ 46,353	$ 65,173	$ 60,376	$ 44,149	$ 216,051
Operating income (loss)	3,603	16,055	158,003	(32,234)	145,427
Net income (loss)	(23,882)	(37,503)	196,429	1,194	136,238
Net income (loss) applicable to common stock	(25,394)	(39,014)	194,917	(318)	130,191
Basic income (loss) per average common share	(0.80)	(1.21)	5.50	(0.01)	3.85
Diluted income (loss) per average common share	(0.80)	(1.21)	4.68	(0.01)	3.48

2007					
Revenues	$ 23,542	$ 28,006	$ 27,280	$ 32,477	$ 111,305
Operating loss	(7,334)	(5,722)	(8,466)	(13,637)	(35,159)
Net income loss	1,036	(3,299)	(22,144)	(20,626)	(45,033)
Net loss applicable to common stock	(476)	(4,811)	(23,655)	(22,138)	(51,080)
Basic loss per average common share	(0.02)	(0.19)	(0.94)	(0.83)	(2.00)
Diluted loss per average common share	(0.02)	(0.19)	(0.94)	(0.83)	(2.00)

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EXHIBIT INDEX

	Exhibit
Ratio of Earnings to Fixed Charges	12.1
Ratio of Earnings to Fixed Charges and Preference Securities Dividends	12.2
Consent of Independent Registered Public Accounting Firm	23.1
Consent of Independent Registered Public Accounting Firm	23.2
Consent of Independent Petroleum Engineers and Geologists	23.3
Certification Pursuant to 15 U.S.C. Section 7241 as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.1
Certification Pursuant to 15 U.S.C. Section 7241 as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.2
Certification Pursuant to 18 U.S.C. Section 1350 as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1
Certification Pursuant to 18 U.S.C. Section 1350 as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.2