ARS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Form 10-K

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

Commission file number 001-32977

GMX RESOURCES INC.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1534474**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
9400 North Broadway, Suite 600, Oklahoma City, Oklahoma	**73114**
(Address of principal executive offices)	**(Zip Code)**

(Registrant's telephone number, including area code) (405) 600-0711

Securities registered under Section 12(b) of the Exchange Act:

Title of Class	Name of Exchange on Which Registered
Common Stock, $0.001 par value	NASDAQ Global Select Market
Series B Cumulative Preferred Stock, $0.001 par value	NASDAQ Global Select Market
Series A Preferred Stock Purchase Rights	NASDAQ Global Select Market

Securities registered under Section 12(g) of the Exchange Act: None

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

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

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 ☒ 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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. Check one:

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act) Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked prices of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. As of June 30, 2008 aggregate market value was $1,109,107,978.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: As of February 26, 2009, there were 18,794,691 shares of Common Stock, par value $.001 per share, outstanding, which included 3,440,000 shares under a share loan which will be returned to the registrant upon conversion or maturity of certain outstanding convertible notes.

DOCUMENTS INCORPORATED BY REFERENCE: Portions of the Company's definitive proxy statement for its 2009 annual meeting of shareholders are incorporated into Part III of this Form 10-K by reference.

GMX RESOURCES INC.
Form 10-K
Table of Contents

PART I

Item 1. Business

General

GMX Resources Inc. (the "Company", "we" or "us") is a "pure play" independent oil and natural gas exploration and production company focused on development of unconventional Haynesville/Bossier Shale and Cotton Valley Sands in the Sabine Uplift of the Carthage, North Field of Harrison and Panola counties of East Texas (our "core area"). We state that we are a "pure play" company because materially all of our business is devoted to drilling for and producing oil and natural gas in one core area.

We have two subsidiaries, Diamond Blue Drilling Co. ("Diamond Blue"), which owns and operates three drilling rigs in our core area, and Endeavor Pipeline Inc. ("Endeavor"), which owns and operates our gathering system in our core area.

Our principal executive office is located at 9400 North Broadway, Suite 600, Oklahoma City, Oklahoma, 73114 and our telephone number is (405) 600-0711.

History

We were incorporated in 1998 and acquired producing and undeveloped oil and natural gas properties located primarily in our core area, Kansas and southeastern New Mexico from a bankruptcy reorganization of a small, privately-held company. We have leased more undeveloped acreage and drilled wells in our core area since 1998. We have since sold the Kansas properties and concentrated our efforts in our core area, primarily since 2003 when we entered into a joint development agreement with Penn Virginia Oil & Gas, L.P. ("PVOG"), a wholly-owned subsidiary of Penn Virginia Corporation (NYSE: PVA). Although this joint development agreement has expired, we continue to own acreage in our core area jointly with PVOG.

Strategy

Our strategy is to grow shareholder value through Haynesville/Bossier Shale horizontal well development as well as Cotton Valley Sand vertical wells, to continue acreage acquisitions, to focus on operational growth in and around our core area, and to convert our unproved natural gas reserves to proved reserves, while maintaining balanced prudent financial management. To date, we have experienced a 100% success rate and have maintained low finding and development costs while primarily drilling Cotton Valley Sand vertical wells. Late in the second quarter of 2008, we switched our strategy from developing the Cotton Valley Sands with vertical wells to the development of Haynesville/Bossier Shale with horizontal wells due to the strong economic profile estimated to be associated with this play.

Develop Haynesville/Bossier acreage. As of December 31, 2008, we had approximately 57,700 gross (38,600 net) acres in the Haynesville/Bossier areas, representing an estimated 480 net unproved drilling locations based on 80-acre well spacing. Initial estimates indicate that the economics of a Haynesville/Bossier Shale well may be significantly better than economics associated with a single Cotton Valley or Travis Peak well. Therefore, we have begun a development program in this formation to prove up potential resources of the play, as well as to enhance cash flow and shareholder value. As of December 31, 2008, we had drilled and completed one Haynesville/Bossier horizontal well and two horizontal wells were drilled and waiting on completion. We were in the process of drilling three Haynesville/Bossier horizontal wells at year-end 2008. The first completed well, Callison 9H (100% working interest), located in Harrison County, Texas and with our shortest planned lateral of 2,000 feet, held an initial production rate of 7.7 Mmcf per day. In 2009, we estimate that we will drill approximately 25 net Haynesville/Bossier horizontal wells using primarily four Helmerich & Payne ("H&P") FlexRigs™.

Expand and maintain production infrastructure. We have built a significant amount of production infrastructure in our core area, which allows us to control marketing, processing and delivery options for the sale of our natural gas and oil. We plan to continue pursuing the best markets for sale of our production and prudently expanding our infrastructure to keep pace with increasing production volumes as we develop our Haynesville/Bossier Shale play.

Fit for purpose drilling rigs. We own and operate three rigs, two of which have the capacity to drill Haynesville/Bossier horizontal wells, and we are currently using two H&P FlexRigs™ under well to well contracts, which allow us the flexibility to pursue our Haynesville/Bossier horizontal drilling plan while having the ability to scale back, if necessary, in a declining commodity price environment. During 2008, we contracted with H&P for four new FlexRigs™ for three year terms to be delivered during 2009, which will be focused exclusively on horizontal development of the Haynesville/Bossier gas shale in our operated acreage. As a result of declining commodity prices, we laid down one of our owned rigs prior to year end 2008 and plan to lay down our other two owned rigs in the first quarter of 2009 when our first two long-term FlexRigs™ arrive. We plan to bring our owned rigs back into operation upon an improvement in natural gas prices. The two FlexRigs™ that are on well to well contracts are currently planned to be released in the second half of 2009.

Expand acreage position. We plan to continue expansion of our acreage position in our core area beyond our current 10-15 year drilling inventory based on current rig utilization and commodity prices, focusing on acreage we will operate. We also intend to review and pursue acquisitions of other properties in our core area, our region or possibly other areas that complement our goal of building shareholder value. From December 31, 2007, to December 31, 2008, we increased our net Haynesville/Bossier acreage position from 18,000 to 38,600 acres, an increase of approximately 114%.

Use leverage and hedging prudently. We expect to fund our drilling activities by maintaining leverage at or near levels equal to shareholders' equity and accessing equity-based funding when market conditions warrant with the goal of limiting dilution to our existing shareholders. We have hedging instruments in place for 2009 for 20,600 Mcfe/day or approximately 67% of our current daily natural gas and crude oil production as of December 31, 2008, and additional hedges exist for production in 2010 and 2011. We plan to continue to use hedging to mitigate commodity price risks and as required by agreements with our lenders.

Company Strengths

Large, continuous acreage position in the heart of the East Texas Haynesville/Bossier Shale and Cotton Valley natural gas plays. The Haynesville/Bossier Shale has only recently received recognition of its potential, with multiple operators entering the play with intentions to contribute significant amounts of capital to development of this resource. We believe that early successful results associated with nearby and offsetting Haynesville/Bossier Shale wells provide further support for our development strategy. We acquired the vast majority of our Haynesville/Bossier Shale position prior to 2008, and have yet to tap the potential available through this play. In 2006, 19 vertical test wells were drilled across our properties. These delineation wells confirmed a consistent 350 foot layer of Haynesville/Bossier Shale present. These wells have substantially reduced the risk associated with our Haynesville/Bossier acreage, which allowed us to begin drilling horizontally in 2008. A significant portion of our Haynesville/Bossier Shale acreage is held by production from our shallower Cotton Valley, Travis Peak and Hosston wells, which also gives us the ability to drill where we choose without risk of lease expiration.

The Cotton Valley resource play is mature and well-understood with many large operators producing natural gas from positions offset to our acreage. As a result of this maturity, drilling results are highly predictable, and we have had a 100% drilling success rate in our seven-year history in the Cotton Valley.

Strong growth profile. Our inventory of nearly 2,000 net proved and unproved Cotton Valley Sand drilling locations and 483 net (721 gross) proved and unproved Haynesville/Bossier Shale locations as of December 31, 2008 is expected to provide us with the ability to continue to grow production and reserves at a high rate. We have grown production and reserves at 75% and 39%, respectively, on average per year for 2007 and 2008.

Favorable economics achieved through investment in infrastructure. We have invested over $101 million in our core area for pipeline gathering systems with approximately 140 miles of gathering and takeaway capacity, compression, salt water disposal and other field infrastructure and in three drilling rigs, two of which we use to drill horizontal Haynesville/Bossier Shale wells. Our net realized price for natural gas volumes sold, including sales of processed liquids, and excluding the effects of hedging, was 95% of the NYMEX price for calendar year 2008. With our current production of 31 MMcfe per day and our takeaway capacity of 80 MMcf per day as of December 31, 2008, we believe there is sufficient capacity based on current infrastructure to support material growth in production.

Low finding and development costs. Our finding and development costs have averaged $1.38 per Mcfe over the last three calendar years. Finding and development costs are calculated by dividing the sum of total exploration and development capital costs by the sum of total additions to estimated proved reserves for the years ended December 31, 2008, 2007 and 2006. "Finding and development costs" are defined in Part I, Item 1—Certain Technical Terms. The Cotton Valley is considered to be an unconventional natural gas resource that is pervasive throughout large areas, which explains our drilling success in this formation. As a result, we did not have any exploration capital costs (*i.e.*, "finding costs") in 2007 or 2006. However, in 2008, the Company had finding costs of $12.2 million related to exploration activities in the Haynesville/Bossier Shale formation.

East Texas

As of December 31, 2008, we owned 386 gross (236 net) producing wells. In our East Texas core area 323 gross (186 net) wells are Cotton Valley wells at depths of 8,000 to 12,000 feet and 56 gross (51 net) wells are productive in the shallower conventional Rodessa, Travis Peak, Hosston and Pettit formations in our core area. In addition we had one Haynesville/Bossier horizontal well producing at year-end 2008. We have grown by developing in our core area with a 100% success rate with low finding and development costs. At December 31, 2008, we had 464.2 Bcfe of proved reserves, which were 94% natural gas, 34% proved developed and more than 99% located in our core area.

We presently have focused the majority of our development efforts on the Haynesville/Bossier Shale areas. As of December 31, 2008, we have approximately 57,700 gross and 38,600 net acres in the Haynesville/Bossier Shale areas, representing an estimated 721 gross (483 net) proved and unproved drilling locations based on 80-acre well spacing.

As of December 31, 2008, we have approximately 60,900 gross and 41,300 net acres in the Cotton Valley area, with 342 net undrilled proved undeveloped Cotton Valley drilling locations based on 20-acre well spacing.

Our core area properties accounted for more than 99% of our total proved reserves at December 31, 2008, 96% of our total net acreage and 99% of our 2008 production.

We operate 158 wells or 41% of our core area gross wells that produce 65% of our oil and natural gas production, as of December 31, 2008. Average daily production net to our interest in 2008 was 32,177 Mcf of gas and 520 Bbls of oil. The producing lives of these fields are generally over 12 to 70 years. Gas sold from the area has a high MMBtu content, which after processing, can result in a net price above average daily Henry Hub natural gas prices. Oil is sold separately at a slight discount to the average Sweet Crude oil price at Cushing, Oklahoma (the NYMEX delivery point), inclusive of deductions. Most of our future development will be added to existing gathering systems under comparable pricing and contracts. The acreage in East Texas lies on the Sabine Uplift, a broad positive feature that acts as a structural trap for most reservoirs. Most of the reservoirs are shallow and deep marine sediments that tend to have tremendous aerial extent and substantial thicknesses. Natural gas and oil production has been produced from 3,000 feet to 11,700 feet in our core area. Prior to shifting our focus to the Haynesville/Bossier, the primary objective of our development was the Cotton Valley Sand, which occurs between 8,200 feet and 10,000 feet and contains multiple layers of sands containing natural gas. Due to the multiple layers and widespread deposition of these gas saturated layers, we have a very high success rate of finding commercial wells.

The following table sets forth the gross and net wells drilled in our core area in 2008:

	Wells Drilled & Completed 2008	
	Gross	Net
Cotton Valley Sands		
Operated	38.0	37.5
50% joint venture with PVOG	23.0	10.6
30% joint venture with PVOG	24.0	7.2
	85.0	55.3
Haynesville/Bossier		
Horizontal	1.0	1.0
Other		
Shallower formations	4.0	3.9
Total	90.0	60.2

In early 2006, we drilled and completed 19 vertical Haynesville/Bossier wells across our property base. The exploratory work found a gas rich unconventional reservoir below the Cotton Valley Sands. We determined from these tests that the reservoirs were very homogenous across all of our acreage in Harrison and Panola counties. We did extensive open hole logging, coring and a variety of completion methods which determined, in our view, a viable horizontal unconventional candidate. We subsequently joined Core Labs Gas Shale consortiums (with approximately 50 other E&P companies) to learn from other operators about horizontal shale development. In early 2008 several E&P companies achieved great success in horizontal Haynesville/Bossier exploration near our properties. We determined the Haynesville/Bossier potential on our properties to be of greater value than the Cotton Valley Sand and gathered the resources necessary to begin Haynesville/Bossier horizontal development. We were also the first company to join Core Labs Haynesville/Bossier Consortium. Currently, we have successfully drilled and completed three Haynesville/Bossier horizontal wells and are drilling four additional horizontal wells. We plan to drill 25 horizontal wells for 2009 and are spending 98% of our 2009 planned capital expenditures on Haynesville/Bossier horizontal wells, related infrastructure and acreage.

Our capital expenditures in 2008 were $328.9 million, of which $39.8 million was expended for tubular and other drilling inventories, $14.4 million for exploratory Haynesville/Bossier drilling in progress at December 31, 2008, $38.2 million was expended on rigs, equipment and gathering systems and the balance was used for drilling and completion of wells, acreage acquisitions and recompletions. The average Cotton Valley vertical well cost for 2008 was approximately $2.1 million.

In 2008, we funded our drilling and development activity in our core area with proceeds of a $125 million offering of our 5.00% convertible senior notes due 2013 in February 2008 and a $141 million common stock offering in July 2008, along with proceeds from borrowings on our revolving bank credit facility and cash flow from operations.

The following table sets forth our proved undeveloped locations in our core area as of December 31, 2008:

	Proved Undeveloped Locations	
	Gross	Net
Operated	243.0	243.0
50% joint venture with PVOG	99.0	49.5
30% joint venture with PVOG	183.0	54.9
Total	525.0	347.4

The operated area includes two Haynesville/Bossier Shale proved undeveloped locations at December 31, 2008.

The pace of future development of this property will depend on availability of capital, future drilling and completion results, the general economic conditions of the energy industry and on the price we receive for the natural gas and crude oil produced. Additionally, in certain areas in which we own our interest jointly with PVOG, the pace of future development will depend on PVOG's level of activity in those areas. Depending on rig availability and funding. We plan on drilling 25 net Haynesville/Bossier Shale horizontal wells in 2009.

If borrowings are not available under our revolving bank credit facility, we may be required to reduce or defer part of our 2009 capital expenditure program or seek additional capital through the issuance of long-term debt or equity.

The number of wells we drill in 2009 will vary, and our potential capital expenditures may vary depending on the number of wells drilled, drilling and completion results, rig availability and other factors. We have budgeted $220 million for capital expenditures in 2009, of which $177 million will be for Haynesville/Bossier horizontal drilling and the balance for acreage acquisitions, developing gathering systems infrastructure and other capital expenditures. We will fund our drilling expenses primarily from internal cash flow and borrowings under our revolving bank credit facility.

As of December 31, 2008, there were four rigs drilling our acreage, two of which are owned by our wholly-owned subsidiary, Diamond Blue, and two of which is on a contract without obligation to us for long-term use. There were no rigs under contract to PVOG that were drilling in our jointly-owned areas at year-end 2008.

Other Properties

We have approximately 600 gross (369 net) acres in the Waskom Field in Clairborne, Caddo, Cataboula and Webster parishes in Louisiana with 5 gross (2.6 net) producing wells, three of which we operate. We also have properties located in Lea and Roosevelt counties, New Mexico, consisting of approximately 1,920 gross (1,458 net) acres with 9 gross (5.7 net) non-operated producing wells. Total reserves and production from these areas represent less than 1% of our proved reserves and 2008 production. We are not actively pursuing additional development of the New Mexico properties.

2009 Plans and Recent Developments

We have 57,700 (38,600 net) acres that are prospective for Haynesville/Bossier development, giving us a total of 721 gross (483 net) 80-acre Haynesville/Bossier horizontal drilling locations. We have recently completed two Haynesville/Bossier horizontal wells and currently have an additional four Haynesville/Bossier horizontal wells drilling. Our Haynesville/Bossier horizontal development in East Texas/Northwest Louisiana continues to be very successful. Our second Haynesville/Bossier horizontal well, the Bosh #11H (100% working interest), was completed in late January, 2009, and had a 24 hour production rate of 7.6 Mmcf per day on a $30/64^{th}$ choke at 4,000 pounds of flowing casing pressure. The lateral length was 3,100 feet. The well had ten fracture treatment stages. Our third Haynesville/Bossier horizontal well, the Baldwin #17H (100% working interest), was completed in February, 2009 and had a 24 hour production rate of 8.7 Mmcf per day on a $30/64^{th}$ choke at 4,200 pounds of flow casing pressure. The lateral length of this well was 4,400 feet in the upper sub-layer of the Haynesville/Bossier Shale. The well had twelve fracture treatment stages. We are locating the laterals of all four Haynesville/Bossier wells currently drilling in the upper sub-layer of the Haynesville/Bossier Shale. We expect the four horizontal wells currently drilling to be completed in the second quarter of 2009. We plan to drill 25 net Haynesville/Bossier horizontal wells in 2009, with projected lateral lengths averaging 4,560 feet.

Gas Gathering

We have acquired, constructed and own, through our wholly-owned subsidiary, Endeavor, gas gathering lines and compression equipment for gathering and delivery of natural gas from our core area that we operate. As of December 31, 2008, we had invested approximately $60 million in this gathering system, including the purchase of compressors, which consisted of approximately 140 miles of gathering lines and compressors that collect and compress gas from approximately 99% of our gas production from wells in our core area. At year end 2008, our gas gathering system had takeaway capacity of 80 MMcf per day compared to our year end production volumes of 31 MMcf per day. In 2009, we expect to build additional miles of pipeline and purchase necessary compressors. This system enables us to improve the control over our production and enhances our ability to obtain access to pipelines for ultimate sale of our gas. We only gather gas from wells in which we own an interest. Remaining gas is gathered by unrelated third parties. Endeavor also serves as first purchaser of gas from wells for which we are the operator. See "Item 1. Business—Marketing."

PVOG has installed and operates gathering facilities to each of the wells drilled and operated by PVOG in our jointly-owned areas. PVOG charges us a gathering fee of $0.10/MMBtu and actual cost of compression plus five percent (5%) for all gas gathered at the wellhead and redelivered to a central sales point. At year end 2008, the PVOG gathering system had takeaway capacity of 80 MMcf per day compared to production of 32.7 MMcf per day.

Diamond Blue Drilling

Our subsidiary, Diamond Blue, owns three drilling rigs as described below:

	Depth Capacity (Feet)	Drawworks Horsepower	Horizontal Capability
DBD #7	11,000	1,000 HP	No
DBD #9	15,000	1,200 HP	Yes
DBD #11	14,000	1,000 HP	Yes

We have approximately $30.5 million invested in these rigs, which are used to drill exclusively on our 100% owned acreage and two of which are presently deployed exclusively for drilling horizontal Haynesville/Bossier Shale wells. The ownership of rigs enables us to better control drilling costs and protects us from rig availability risks when rigs are in high demand. Due to the decline in natural gas prices and our long-term drilling contracts for four rigs from H&P, we intend to lay these rigs down in 2009 until natural gas prices increase and capital is available to accelerate our drilling program.

Reserves

As of December 31, 2008, MHA Petroleum Consultants, Inc. estimated our proved reserves to be 465.3 Bcfe. An estimated 162.1 Bcfe is expected to be produced from existing wells and another 303.2 Bcfe is classified as proved undeveloped. Substantially all of our proved reserves relate to our Cotton Valley Sands development. All of our proved undeveloped reserves are on locations that are adjacent to wells productive in the same formations.

The following table shows the estimated net quantities of our proved reserves as of the dates indicated and the Estimated Future Net Revenues and Present Values attributable to total proved reserves at December 31:

	2006	2007	2008
Proved Developed:			
Gas (Bcf)	69.3	144.2	150.6
Oil (MMBbls)	.9	1.8	1.9
Total (Bcfe)	74.9	155.0	162.1
Proved Undeveloped:			
Gas (Bcf)	167.6	262.1	284.7
Oil (MMBbls)	1.8	2.9	3.1
Total (Bcfe)	178.1	279.5	303.2
Total Proved:			
Gas (Bcf)	236.9	406.3	435.3
Oil (MMBbls)	2.7	4.7	5.0
Total (Bcfe)	253.0	434.5	465.3
Estimated Future Net Revenues[1] ($000s)	$519.5	$1,896.3	$2,586.6
Present Value[1] ($000s)	$173.3	$ 592.8	$ 280.7
Standardized Measure[1] ($000s)	$134.4	$ 427.7	$ 228.8

1 The prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as of period end. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. See "Note L—Supplemental Information on Oil and Natural Gas Operations" in our consolidated financial statements for information about the standardized measure of discounted future net cash flows. We believe that the Estimated Future Net Revenue and Present Value are useful measures in addition to the standardized measure as it assists in both the determination of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. The standardized measure is dependent on the unique tax situation of each individual company, while the pre-tax Present Value is based on prices and discount factors that are consistent from company to company. We also understand that securities analysts use this measure in similar ways.

The increases in proved reserves, Present Value and Standardized Measure in 2008 are primarily attributable to extensions, discoveries and revisions of prior estimates resulting from our core area drilling results.

Approximately 65% of our proved reserves are undeveloped. The quantity and value of our proved undeveloped reserves are dependent upon our ability to fund the associated development costs, which were an estimated $559.8 million in the aggregate as of December 31, 2008, of which approximately $190 million is scheduled to be expended in 2009. We have examined all sources of available funding, including our expected operating cash flows, availability under our revolving bank credit facility, and potential future debt and equity issuances, and we are reasonably certain that we will be able to fund the necessary development costs for our proved undeveloped reserves.

Estimated Future Net Revenues and Present Value are highly sensitive to commodity price changes, and commodity prices have recently been highly volatile. Period end prices are not necessarily the prices we expect to receive for our production, but we are required by the SEC to use them for disclosure purposes. We estimate that if all other factors (including the estimated quantities of economically recoverable reserves) were held constant, a $1.00 per Bbl change in oil prices and a $0.10 per Mcf change in gas prices from those used in calculating the Present Value would change such Present Value by approximately $2 million and $15.8 million, respectively, as of December 31, 2008.

The estimates of proved reserves at December 31, 2007 and 2008 were prepared by MHA Petroleum Consultants, Inc. The estimates of proved reserves at December 31, 2006 were prepared by MHA Petroleum Consultants, Inc., in association with Sproule Associates, Inc.

No estimates of our proved reserves comparable to those included in this report have been included in reports to any federal agency other than the SEC.

Costs Incurred

The following table shows certain information regarding the costs incurred by us in our acquisition, exploration, and development activities during the periods indicated.

	2006	2007	2008
		(in thousands)	
Development and exploration costs:			
Development drilling	$ 99,778	$168,246	$183,081
Exploratory drilling	—	—	15,943
Tubular and other drilling inventories	—	—	39,773
Asset retirement obligation	337	1,463	2,407
	100,115	169,709	241,204
Acquisition:			
Proved	4,542	7,814	23,246
Unproved	598	1,018	26,236
	5,140	8,832	49,482
Total	$105,255	$178,541	$290,686

Drilling Results

We drilled or participated in the drilling of wells as set out in the table below for the periods indicated. The table was completed based upon the date drilling commenced. We did not acquire any wells or conduct any exploratory drilling during 2006 and 2007. You should not consider the results of prior drilling activities as necessarily indicative of future performance, nor should you assume that there is necessarily any correlation between the number of productive wells drilled and the oil and natural gas reserves generated by those wells.

	Year Ended December 31,					
	2006		2007		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Gas	67.0	35.3	127.0	76.5	89.0	59.2
Oil	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Exploratory wells:						
Gas	—	—	—	—	1.0	1.0
Total	67.0	35.3	127.0	76.5	90.0	60.2

As of December 31, 2008, we had three Haynesville/Bossier horizontal wells drilling that are not included in the table above.

Acreage

The following table shows our developed and undeveloped oil and natural gas lease and mineral acreage as of December 31, 2008. Excluded is acreage in which our interest is limited to royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
East Texas	38,852	22,859	24,154	20,323	63,006	43,182
Other	2,520	1,827	—	—	2,520	1,827
Total	41,372	24,686	24,154	20,323	65,526	45,009

Within the total gross and net East Texas acres is 57,700 gross and 38,600 net acres which we believe to be prospective Haynesville/Bossier acreage.

Title to oil and natural gas acreage is often complex. Landowners may have subdivided interests in the mineral estate. Oil and natural gas companies frequently subdivide the leasehold estate to spread drilling risk and often create overriding royalties. When we purchased the properties, the purchase included title opinions prepared by counsel analyzing mineral ownership in each well drilled. Further, for each producing well there is a division order signed by the current recipients of payments from production stipulating their assent to the fraction of the revenues they receive. We obtain similar title opinions with respect to each new well drilled. While these practices, which are common in the industry, do not assure that there will be no claims against title to the wells or the associated revenues, we believe that we are within normal and prudent industry practices. Because many of the properties in our current portfolio were purchased out of bankruptcy in 1998, we have the advantage that any known or unknown liens against the properties were cleared in the bankruptcy.

Productive Well Summary

The following table shows our ownership in productive wells as of December 31, 2008. Gross oil and natural gas wells include one well with multiple completions. Wells with multiple completions are counted only once for purposes of the following table.

	Productive Wells	
	Gross	Net
Natural gas	361.0	216.3
Oil	25.0	19.7
Total	386.0	236.0

Substantially all of our productive wells are related to our Cotton Valley Sands development.

Facilities

As of December 31, 2008, we leased 15,902 square feet in Oklahoma City, Oklahoma for our corporate headquarters. The annual rental cost is approximately $252,000. We also lease 5,000 square feet of office space in Marshall, Texas used primarily for land field operations. The annual rent is approximately $24,000.

We own a 50-acre operations field yard approximately seven miles southeast of Marshall, Texas that has 10,800 square feet of office and warehouse space. We also own 48 acres on which our gas gathering sales point is located. In addition, we own 100 acres for expansion of our field operations near Marshall, Texas. In 2008, we opened a second field office of approximately 2,000 square feet dedicated to land operations situated on 14 acres approximately two miles from the operations field yard.

Employees

As of December 31, 2008, we had 149 full-time employees, including 60 employees of Diamond Blue. This compares to 115 full-time employees at December 31, 2007, including 74 employees of Diamond Blue. We also use a number of independent contractors to assist in land and field operations. We believe our relations with our employees are satisfactory. Our employees are not covered by a collective bargaining agreement.

Marketing

Our ability to market oil and natural gas often depends on factors beyond our control. The potential effects of governmental regulation and market factors, including alternative domestic and imported energy sources, available pipeline capacity, and general market conditions are not entirely predictable.

Natural Gas. Natural gas is generally sold pursuant to individually negotiated gas purchase contracts, which vary in length from spot market sales of a single day to term agreements that may extend several years. Customers who purchase natural gas include marketing affiliates of the major pipeline companies, natural gas marketing companies, and a variety of commercial and public authorities, industrial, and institutional end-users who ultimately consume the gas. Gas purchase contracts define the terms and conditions unique to each of these sales. The price received for natural gas sold on the spot market may vary daily, reflecting changing market conditions. The deliverability and price of natural gas are subject to both governmental regulation and supply and demand forces.

Substantially all of our gas from our East Texas company-operated wells is initially sold to our wholly owned subsidiary, Endeavor, which in turn sells gas to unrelated third parties. All of our gas is currently sold under contracts providing for market sensitive terms that are terminable with 30-60 day notice by either party without penalty. This means that we both enjoy the benefits of high prices in increasing price markets and suffer the impact of low prices when gas prices decline. In addition, PVOG markets 100% of the gas produced from wells operated by PVOG in areas we jointly own. A subsidiary of PVOG charges us a marketing fee of 1% of the sales proceeds subject to certain price caps for oil and natural gas sold on our behalf in areas we jointly own.

Crude Oil. Oil produced from our properties is sold at the prevailing field price to one or more of a number of unaffiliated purchasers in the area. Generally, purchase contracts for the sale of oil are cancelable on 30 days' notice. The price paid by these purchasers is an established market or "posted" price that is offered to all producers.

We do not currently have any long-term contracts to sell natural gas or crude oil.

In 2008, our largest purchasers of oil and natural gas were various purchases through PVOG and Crosstex Energy Services, Inc. which accounted for 42% and 22% of total oil and natural gas sales, respectively. We do not believe that the loss of any of our purchasers would have a material adverse affect on our operations as there are other purchasers active in the market.

Competition

We compete with major integrated oil and natural gas companies and independent oil and natural gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. 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 could adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional 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. In addition, most of our competitors have operated for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Recent increased oil and natural gas drilling activity in East Texas has resulted in increased demand for drilling rigs and other oilfield equipment and services. At various times, we have and may continue to experience occasional or prolonged shortages or unavailability of drilling rigs, drill pipe and other material used in oil and natural gas drilling. Such unavailability could result in increased costs, delays in timing of anticipated development or cause interests in undeveloped oil and natural gas leases to lapse.

Regulation

Exploration and Production. The exploration, production and sale of oil and natural gas are subject to various types of local, state and federal laws and regulations. These laws and regulations govern a wide range of matters, including the drilling and spacing of wells, allowable rates of production, restoration of surface areas, plugging and abandonment of wells and requirements for the operation of wells. Our operations are also subject to various conservation requirements. These include the regulation of the size and shape of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of oil and natural gas properties. In this regard, some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. All of these regulations may adversely affect the rate at which wells produce oil and natural gas and the number of wells we may drill. All statements in this report about the number of locations or wells reflect current laws and regulations.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

Environmental Matters. The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require us to incur costs to remedy discharges. Natural gas, oil or other pollutants, including salt water brine, may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from pipelines or other gathering and transportation facilities, leakage from storage tanks and sudden discharges from damage or explosion at natural gas facilities of oil and natural gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities.

A variety of federal and state laws and regulations govern the environmental aspects of natural gas and oil production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges, whether or not accidental, failure to notify the proper authorities of a discharge, and other noncompliance with those laws. Compliance with such laws and regulations may increase the cost of oil and natural gas exploration, development and production, although we do not anticipate that compliance will have a material adverse effect on our capital expenditures or earnings. Failure to comply with the requirements of the applicable laws and regulations could subject us to substantial civil and/or criminal penalties and to the temporary or permanent curtailment or cessation of all or a portion of our operations.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund law," imposes liability, regardless of fault or the legality of the original conduct, on some 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 a disposal site or sites where the release occurred and companies that dispose or arrange for disposal of the hazardous substances found at the time. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and severable liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We could be subject to the liability under CERCLA because our drilling and production activities generate relatively small amounts of liquid and solid waste that may be subject to classification as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

There are numerous state laws and regulations in the states in which we operate which relate to the environmental aspects of our business. These state laws and regulations generally relate to requirements to remediate spills of deleterious substances associated with oil and natural gas activities, the conduct of salt water disposal operations, and the methods of plugging and abandonment of oil and natural gas wells which have been unproductive. Numerous state laws and regulations also relate to air and water quality.

We do not believe that our environmental risks will be materially different from those of comparable companies in the oil and natural gas industry. We believe our present activities substantially comply, in all material respects, with existing environmental laws and regulations. Nevertheless, we cannot assure you that environmental laws will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our financial condition and results of operations. Although we maintain liability insurance coverage for liabilities from pollution, environmental risks generally are not fully insurable.

In addition, because we have acquired and may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Marketing and Transportation. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the Federal Energy Regulatory Commission ("FERC") that affect the economics of natural gas production, transportation and sales. In addition, FERC is continually proposing and implementing new rules affecting segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The ultimate impact of the complex rules and regulations issued by FERC since 1985 cannot be predicted. We cannot predict what further action FERC will take on these matters. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

Additional proposals and proceedings that might affect the natural gas industry are frequently made before Congress, FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue.

Our sales of crude oil and condensate are currently not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. However, we do not believe that these regulations affect us any differently than other crude oil producers.

Certain Technical Terms

The terms whose meanings are explained in this section are used throughout this document:

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

Btu. British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

BBtu. Billion Btus.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Location. A location on which a development well can be drilled.

Development Well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive in an attempt to recover proved undeveloped reserves.

Drilling Unit. An area specified by governmental regulations or orders or by voluntary agreement for the drilling of a well to a specified formation or formations which may combine several smaller tracts or subdivides a large tract, and within which there is usually some right to share in production or expense by agreement or by operation of law.

Dry Hole. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Estimated Future Net Revenues. Estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development costs, and future abandonment costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization.

Exploratory Well. A well drilled to find and produce oil or gas 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.

Finding and Development Costs. The total costs incurred for exploration and development activities (excluding exploratory drilling in progress and drilling inventories), divided by total proved reserve additions. To the extent any portion of the proved reserve additions consist of proved undeveloped reserves, additional costs would have to be incurred in order for such proved undeveloped reserves to be produced. This measure may differ from the measure used by other oil and natural gas companies.

Gross Acre. An acre in which a working interest is owned.

Gross Well. A well in which a working interest is owned.

Infill Drilling. Drilling for the development and production of proved undeveloped reserves that lie within an area bounded by producing wells.

Injection Well. A well which is used to place liquids or gases into the producing zone during secondary/ tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field or productive horizons.

Lease Operating Expense. All direct costs associated with and necessary to operate a producing property.

MBbls. Thousand barrels.

MBtu. Thousand Btus.

Mcf. Thousand cubic feet.

Mcfpd. Thousand cubic feet per day.

Mcfe. Thousand cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

MMBbls. Million barrels.

MMBtu. Million Btus.

MMcf. Million cubic feet.

MMcfe. Million cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

Natural Gas Liquids. Liquid hydrocarbons which have been extracted from natural gas (e.g., ethane, propane, butane and natural gasoline).

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease, usually pursuant to the terms of a joint operating agreement among the various parties owning the working interest in the well.

Present Value. When used with respect to oil and natural gas reserves, present value means the Estimated Future Net Revenues discounted using an annual discount rate of 10%.

Productive Well. A well that is producing oil or gas or that is capable of production.

Proved Developed Reserves. Proved reserves are expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by pilot project or after the operation of an installed program as confirmed through production response that increased recovery will be achieved.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Undeveloped Reserves. 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances can estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale), but generally does not require the owners to pay any portion of the costs of drilling or operating wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of a leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with the transfer to a subsequent owner.

Secondary Recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and water flooding are examples of this technique.

Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

Workover. To carry out remedial operations on a productive well with the intention of restoring or increasing production.

Availability of Information

We file periodic reports and proxy statements with the Securities and Exchange Commission ("SEC"). The public may read and copy any materials 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 about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of this site is http://www.sec.gov.

Our internet address is www.gmxresources.com. We make available on our website free of charge copies of our annual report 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) of the Exchange Act as soon as reasonably possible after we electronically file or furnish such material with the SEC.

Item 1A. Risk Factors.

Risks Related to GMX

The loss of our President or other key personnel could adversely affect us.

We depend to a large extent on the efforts and continued employment of Ken L. Kenworthy, Jr., our President and Chief Executive Officer. The loss of his services could adversely affect our business. In addition, if Mr. Kenworthy resigns or we terminate him as our president, we would be in default under our revolving bank credit facility, and we would also be required to offer to repurchase all of our senior secured notes and outstanding Series B Preferred Stock. If Mr. Kenworthy dies or becomes disabled, we would be required to offer to repurchase all of our outstanding Series B Preferred Stock, and unless we appoint a successor acceptable to our secured creditors within four months of Mr. Kenworthy's death or disability, we would also be in default under our revolving bank credit facility and required to offer to repurchase all of our senior secured notes.

Our wells produce oil and natural gas at a relatively slow rate.

We expect that our existing wells and other wells that we plan to drill on our existing properties will produce the oil and natural gas constituting the reserves associated with those wells over a period of between 12 and 70 years. By contrast, natural gas wells located in other areas of the United States, such as offshore Gulf coast wells, may produce all of their reserves in a shorter period, for example, four to seven years. Because of the relatively slow rates of production of our wells, our reserves will be affected by long term changes in oil or natural gas prices or both, and we will be limited in our ability to anticipate any price declines by increasing rates of production. We may hedge our reserve position by selling oil and natural gas forward for limited periods of time, but we do not anticipate that, in declining markets, the price of any such forward sales will be attractive.

Our future performance depends upon our ability to obtain and commit capital to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. The business of exploring for, developing or acquiring reserves is capital intensive. Our ability to make the necessary capital investment to maintain or expand our oil and natural gas reserves is limited by our relatively small size. Further, our East Texas joint development partner, PVOG, may propose drilling that would require more capital than we have available from cash flow from operations or our revolving bank credit facility. In such case, we would be required to seek additional sources of financing or limit our participation in the additional drilling. Due to the current global financial and economic crisis and a decline in natural gas and oil prices, we have reduced our capital expenditure budget for 2009. This reduction will limit our ability to find or acquire additional reserves and to develop our existing reserves. In addition, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be encountered.

Hedging our production may result in losses or limit potential gains.

We enter into hedging arrangements to limit our risk to decreases in commodity prices and as required under our senior secured note agreement. Hedging arrangements expose us to risk of financial loss in some circumstances, including the following:

- production is less than expected;
- the counter-party to the hedging contract defaults on its contact obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these hedging arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas. If we choose not to engage in hedging arrangements in the future, we may be more adversely affected by changes in oil and natural gas prices than our competitors, who may or may not engage in hedging arrangements.

Our revolving bank credit facility and senior secured note agreement contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals. If our revolving bank credit facility or our senior secured note agreement were to be accelerated, we may not have sufficient liquidity to repay our indebtedness in full.

Our revolving bank credit facility and secured note agreement each include certain covenants that, among other things, restrict:

- our investments, loans and advances and the paying of dividends on common stock and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;
- mergers, consolidations and sales of all or a substantial part of our business or properties; and
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities.

Our revolving bank credit facility and senior secured note agreement require us to maintain certain financial ratios, including adjusted PV-10 to total debt, total debt to EBITDA, and EBITDA to interest ratios. All of these restrictive covenants may restrict our ability to expend or pursue our business strategies. Our ability to comply with these and other provisions of our revolving bank credit facility and senior secured note agreement may be impacted by lower commodity prices, changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our revolving bank credit facility and senior secured note agreement, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our revolving bank credit facility and senior secured note agreement, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. The amounts we can borrow under our revolving bank credit facility are subject to a borrowing base calculation that depends on the value that our banks place on our oil and natural gas properties. Lower commodity prices may result in a reduction of our borrowing base. If the indebtedness under our revolving bank credit facility or senior secured note agreement were to be accelerated, our convertible senior notes due 2013 would also be accelerated and we may not have sufficient liquidity to repay our indebtedness in full.

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business and stock price.

We have evaluated our internal controls systems to allow management to report on, and our independent auditors to audit, our internal controls over financial reporting. We have performed the system and process evaluation and testing required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002. We have not identified control deficiencies under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. As a public company, we are required to report, among other things, control deficiencies that constitute a "material weakness" or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. A "material weakness" is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim consolidated financial statements will not be prevented or detected. The report by us of a material weakness may cause investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

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. In response to the current global financial and economic crisis and a decline in natural gas and oil prices, we have reduced our capital expenditure budget for 2009. This reduction will decrease the number of wells that we develop. Complications in the development of any single material well may result in a material adverse affect on our financial condition and results of operations. If we were to experience operational problems resulting in the curtailment of production in a material number of our wells, our total production levels would be adversely affected, which would have a material adverse affect on our financial condition and results of operations.

A majority of our production, revenue and cash flow from operating activities is derived from assets that are concentrated in a 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 East Texas wells. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. Approximately 98% of our estimated proved reserves relate to wells in the Cotton Valley and shallower formations. We plan to devote a smaller portion of our capital expenditure budget to the Cotton Valley formation in favor of wells to develop the Haynesville/Bossier Shale formation. This may affect the production, revenue and cash flow we derive from further development of the Cotton Valley formation.

Servicing our debt requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial debt.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not continue to generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at such time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on the market price of our equity securities.

We embarked on a new exploration and development program in the Haynesville/Bossier Shale in 2008, and it is difficult to predict drilling success rates.

Commencing in the third quarter of 2008, we have directed a majority of our development focus to the drilling of horizontal wells in the Haynesville/Bossier Shale formation in our core area. These activities represent a change from our historic focus of drilling developmental vertical wells to the Cotton Valley formation. Part of our drilling strategy to maximize recoveries from the Haynesville/Bossier Shale formation involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling in the Haynesville/Bossier Shale formation to date is limited. Furthermore, while the wells drilled in the Haynesville/Bossier Shale formation to date have reported very high initial production rates, our production history in this area is still limited, and we are less able to use past drilling results in this areas to help predict our future drilling results. We may not encounter the same drilling results in the Haynesville/Bossier Shale wells, in which event our results of operations or financial condition may be adversely affected.

We recently entered into a long-term rig contract, which will require a significant portion of our budgeted capital expenditures over its term.

In 2008, we entered into an agreement with Helmerich & Payne for four new FlexRigs(TM) for three-year terms each, all of which will be delivered in 2009. Over the three year term for the four rigs, we will be obligated to pay $145.5 million. This represents a significant portion of our future capital expenditures budget. The presence of this commitment will limit our ability to deploy our capital to other projects. Additionally, the term of these commitments restricts our flexibility to adjust the scale of our drilling efforts based on prevailing commodity prices and other industry conditions, meaning that we will continue to be obligated to pay for these rigs even if market conditions do not render their use economical for us. As such, this long-term commitment could have an adverse effect on our financial condition and results of operations.

Increased drilling in the Haynesville/Bossier Shale formation in and around our core area may cause pipeline capacity problems that may limit our ability to sell natural gas.

If the Haynesville/Bossier Shale continues to be successful, the amount of gas being produced in and around our core area from these new wells, as well as other existing wells, may exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, pipeline projects that are planned for the Haynesville/Bossier Shale formation may not move forward 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 and/or sell natural gas production at significantly lower prices than we currently project, which would adversely affect our results of operations.

The current global economic crisis could adversely impact our business and financial condition.

In 2008, general worldwide economic conditions deteriorated sharply due to the subprime lending crisis, general credit market crisis, collateral effects on the financial and banking industries, decreased consumer confidence, reduced corporate profits and capital spending, and liquidity concerns. These conditions could limit our access to capital and additionally make it difficult for us to accurately forecast and plan future business activities. These conditions also could impact the ability of third parties that purchase natural gas and oil production from us to fulfill their payment obligations to us on a timely basis. The economic situation could also cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. We cannot predict the timing or duration of the global economic crises or the timing or strength of a subsequent economic recovery. If the economy experiences continued weakness at current levels or deteriorates further, our business, financial condition and results of operations could be materially and adversely affected. Additionally, continued weakness in the global economy could result in reduced demand, and consequently lower prices, for oil and natural gas, which would adversely affect our revenues, operating cash flow and ability to obtain capital.

We recently received comments from the SEC staff in connection with the staff's routine review of our filings. The SEC's review is not yet complete, and we may be required, to make changes, including lowering the amount of reported reserves, to our filings in order to respond to the SEC staff's comments.

In connection with a routine review of certain filings, the staff of the SEC (the "Staff") has provided us with comments regarding various aspects of the proved reserves reported at December 31, 2006 and 2007, and the production forecasts contained in our 2006 reserve report. Primarily, the Staff has requested additional information relating to the differences between the production estimated for our proved undeveloped reserves in our reserve reports versus our actual production and the decline rates we utilize to estimate our proved developed reserves. We have responded to the Staff's comments and will promptly respond with supplemental information responsive to the Staff's latest comment letter received on February 24, 2009.

We believe the methodology we used to prepare our reserve estimates was appropriate. After we provide the Staff with the information it has most recently requested, we believe we will be in a position to resolve all of the prior comments we have received from the Staff, although it is possible the Staff will raise additional issues. Until the Staff's position is more certain, there is a risk that our reserve estimates may require amendments, and if so, we may be required to restate our financial statements. Any such amendments or restatements could have an adverse effect on the market price for our common stock.

If the Staff disagrees with our position with respect to our reserves at December 31, 2006 and 2007 or raises new issues upon reviewing our reserves at December 31, 2008 included in this Annual Report, and we are unable to subsequently satisfactorily resolve the Staff's concerns, we may be required to amend our filings to lower the amount of reserves reported, which would in turn possibly require a restatement of our financial statements for prior periods to reflect depletion at a higher rate than has been previously reported, which would in turn reduce our previously reported net income and net income per share. Any such restatement would not affect previously reported cash flow from operating activities. We do not anticipate that any change in reported reserve quantities would require any write down of the value of oil and natural gas properties on our 2008 year-end balance sheet. The exact quantity of any reserve quantity adjustment that may be ultimately required, if any, is not yet certain.

Risks Related to the Oil and Natural Gas Industry

Oil and natural gas prices have a material impact on us.

Lower oil and natural gas prices would adversely affect our financial position, financial results, cash flows, access to capital and ability to grow. Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for the oil and natural gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow under our revolving bank credit facility is subject to periodic redeterminations based on the valuation by our banks of our oil and natural gas reserves, which will depend on oil and natural gas prices used by our banks at the time of determination. In addition, we may have full-cost ceiling test write-downs in the future if prices fall significantly.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil and natural gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil and natural gas producing regions, and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and natural gas prices do not necessarily move in tandem. Because approximately 93.6% of our reserves at December 31, 2008 are natural gas reserves, we are more affected by movements in natural gas prices.

We may encounter difficulty in obtaining equipment and services.

Higher oil and natural gas prices and increased oil and natural gas drilling activity generally stimulate increased demand and result in increased prices and unavailability for drilling rigs, crews, associated supplies, equipment and services. While we have recently been successful in acquiring or contracting for services, we could experience difficulty obtaining drilling rigs, crews, associated supplies, equipment and services in the future. These shortages could also result in increased costs or delays in timing of anticipated development or cause interests in oil and natural gas leases to lapse. We cannot be certain that we will be able to implement our drilling plans or at costs that will be as estimated or acceptable to us.

Due to the recent increase of drilling Haynesville/Bossier Shale wells in and around our core area, demand for higher pressure downhole pipe and other equipment necessary for drilling these wells has been very high. If we are unable to obtain this equipment in a timely manner, the implementation of our Haynesville/Bossier Shale drilling plans could be delayed.

Estimates of proved natural gas and oil reserves and present value of proved reserves are not precise.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, the precision of the engineering and geological interpretation, and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. A reduction in oil and natural gas prices not only would reduce the value of any proved reserves, but also might reduce the amount of oil and natural gas that could be economically produced, thereby reducing the quantity of reserves. Our proved reserves are estimated using assumptions of decline rates based on historic experience. Due to the limited production history we have in our core area, our initial assumptions of decline rates are subject to modification as we gain more experience in operating our wells. In 2007 and 2008, we experienced shortfalls in actual production for new wells compared to production estimates used in our 2006 reserve report. Our reserves and future cash flows may be subject to revisions, based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse affect on our financial condition and operating results.

At December 31, 2008, approximately 65% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures of $559.8 million to develop these reserves, including approximately $190 million in 2009. However, these estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

We may incur write-downs of the net book values of our oil and natural gas properties that would adversely affect our shareholders' equity and earnings.

The full cost method of accounting, which we follow, requires that we periodically compare the net book value of our oil and natural gas properties, less related deferred income taxes, to a calculated "ceiling." The ceiling is the estimated after-tax present value of the future net revenues from proved reserves using a 10% annual discount rate and using constant prices and costs. Any excess of net book value of oil and natural gas properties is written off as an expense and may not be reversed in subsequent periods even though higher oil and natural gas prices may have increased the ceiling in these future periods. A write-off constitutes a charge to earnings and reduces shareholders' equity, but does not impact our cash flows from operating activities. On December 31, 2008, we recorded an impairment charge of $151.6 million on our oil and natural gas properties due to a ceiling test write-down based on a natural gas price of $5.71 per Mmbtu and a crude oil price of $44.60 per barrel at December 31, 2008. If commodity prices continue to be weak, we may be subject to additional ceiling test write-downs. Future write-offs may occur that would have a material adverse effect on our net income in the period taken, but would not affect our cash flows. Even though such write-offs do not affect cash flow, they could have an adverse effect on the price of our publicly traded securities.

Operational risks in our business are numerous and could materially impact us.

Our operations involve operational risks and uncertainties associated with drilling for, and production and transportation of, oil and natural gas, all of which can affect our operating results. Our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including:

- the presence of unanticipated pressure or irregularities in formations;
- accidents;
- title problems;
- weather conditions;
- compliance with governmental requirements;
- shortages or delays in the delivery of equipment;
- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties; and
- other losses resulting in suspension of our operations.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above with a general liability and commercial umbrella policy. We do not maintain insurance for damages arising out of exposure to radioactive material. Even in the case of risks against which we are insured, our policies are subject to limitations and exceptions that could cause us to be unprotected against some or all of the risk. The occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations.

Governmental regulations could adversely affect our business.

Our business is subject to certain federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters. These laws and regulations have increased the costs of our operations. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

Environmental liabilities could adversely affect our business.

In the event of a release of oil, natural gas or other pollutants from our operations into the environment, we could incur liability for any and all consequences of such release, including personal injuries, property damage, cleanup costs and governmental fines. We could potentially discharge these materials into the environment in several ways, including:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

In addition, because we may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination that we have not yet discovered relating to the acquired properties or our other properties.

To the extent we incur any environmental liabilities, it could adversely affect our results of operations or financial condition.

Competition in the oil and natural gas industry is intense, and we are smaller than many of our competitors.

We compete with major integrated oil and natural gas companies and independent oil and natural gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. 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 exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional 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.

Risks Related to Our Common Stock

Shares eligible for future sale may depress our stock price.

As of February 26, 2009, we had 18,794,691 shares of common stock outstanding, of which 1,649,372 shares were held by affiliates (in addition, 583,050 shares of common stock were subject to outstanding options granted under our stock option plan of which 239,250 shares were vested as of February 26, 2009). All of the shares of common stock held by our affiliates are restricted or control securities eligible for resale under Rule 144 promulgated under the Securities Act. The shares of our common stock issuable upon exercise of the stock options have been registered under the Securities Act. In addition, we have agreed to register for public offering up to 3,846,150 shares of our common stock that may be borrowed under the share lending agreement entered into in February 2008 concurrently with the pricing of the convertible senior notes due 2013. Shares that we lend under the share lending agreement may be returned to us by the share borrower and reborrowed during the term of the share lending agreement. At February 26, 2009, our outstanding shares included 3,440,000 shares of common stock loaned under this agreement. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of our common stock and could impair our ability to raise additional capital through the sale of equity securities.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Our common stock is traded on The NASDAQ Global Select Market. The market price of our common stock has been volatile and could fluctuate substantially based on a variety of factors, including the following:

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the industry;
- market conditions; and
- analysts' estimates and other events in the natural gas and crude oil industry.

Future issuance of additional shares of our common stock could cause dilution of ownership interests and adversely affect our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our shareholders. We are currently authorized to issue 50,000,000 shares of common stock on such terms as determined by our board of directors. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our preferred stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

The issuance of our common stock pursuant to a share lending agreement, including sales of the shares that we lend, and other market activity related to the share lending agreement may lower the market price of our common stock.

In connection with our offering of convertible notes in February 2008, we entered into a share lending agreement with an affiliate (the "share borrower") of Jefferies & Company, Inc., one of the initial purchasers of the notes. We agreed to lend up to 3,846,150 shares of our common stock to the share borrower, of which 2,140,000 shares of our common stock were sold in February 2008 in a fixed price offering and up to 1,706,150 additional shares of our common stock may be sold in an at-the-market offering following the fixed price offering, both offerings registered under the Securities Act. We have loaned a total of 3,440,000 of the at-the-market shares to date. To the extent we lend any additional shares to the share borrower, the share borrower will sell those additional shares to the public in an offering registered under the Securities Act.

Jefferies & Company, Inc. informed us that it, or its affiliates, used the short position created by the sale of our common stock in the fixed price offering to facilitate transactions by which investors in the notes may hedge their investment in the notes through privately negotiated derivative transactions (the "share loan hedges"). The share loan hedges are expected to unwind during an applicable observation period immediately prior to the maturity, repurchase or conversion of our convertible notes and to terminate on the last trading day of such observation period.

The increase in the number of outstanding shares of our common stock issued pursuant to the share lending agreement and sales of the borrowed shares could have a negative effect on the market price of our common stock. The market price of our common stock also could be negatively affected by other short sales of our common stock by purchasers of our convertible notes to hedge their investment in the convertible notes from time to time. During any period immediately prior to the maturity, repurchase or conversion of our convertible notes, the share borrower, or its affiliates, and its counterparties to share loan hedges may engage in sales and purchases of our common stock in connection with the unwinding of the share loan hedges. In addition, during the term of the share loan hedges the counterparties thereto may engage in purchases or sales of shares of our common stock in connection with the hedging of their investment in our convertible notes. We cannot predict with certainty the effect, if any, that these future sales and purchases of our common stock will have on the market price of our common stock. However, sales of our common stock during such periods, or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our existing preferred stock has greater rights than our common stock, and we may issue additional preferred stock in the future.

We have one series of preferred stock outstanding. Although we have no current plans, arrangements, understandings or agreements to issue any additional preferred stock, our certificate of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our shareholders. Our existing preferred stock and any future preferred stock may also rank ahead of our common stock in terms of dividends and liquidation rights. If we issue additional preferred stock, it may adversely affect the market price of our common stock. In addition, the issuance of convertible preferred stock may encourage short selling by market participants because the conversion of convertible preferred stock could depress the price of our common stock.

Our common stock is an unsecured equity interest in our company.

As an equity interest, our common stock is not secured by any of our assets. Therefore, in the event we are liquidated, the holders of our common stock will receive a distribution only after all of our secured and unsecured creditors have been paid in full. There can be no assurance that we will have sufficient assets after paying our secured and unsecured creditors to make any distribution to the holders of our common stock.

Anti-takeover provisions in our organizational documents, our convertible senior notes, other outstanding debt and Oklahoma law could have the effect of discouraging, delaying or preventing a merger or acquisition, which could adversely affect the market price of our common stock.

Several provisions of our certificate of incorporation, bylaws and Oklahoma law may discourage, delay or prevent a merger or acquisition that shareholders may consider favorable.

These provisions include:

- a shareholder rights plan;
- authorizing our board of directors to issue "blank check" preferred stock without shareholder approval;
- prohibiting cumulative voting in the election of directors;
- limiting the persons who may call special meetings of shareholders;
- establishing advance notice requirements for election to our board of directors or proposing matters that can be acted on by shareholders at shareholder meetings; and
- prohibiting shareholders from amending our bylaws.

In addition, a change in control is an event of default under our revolving bank credit facility, and a change in control also requires us to offer to purchase our senior secured notes, our Series B Preferred Stock and our convertible senior notes.

These anti-takeover provisions could substantially impede the ability of public shareholders to benefit from a change in control and, as a result, may adversely affect the market price of our common stock and your ability to realize any potential change of control premium.

We have not paid dividends and do not anticipate paying any dividends on our common stock in the foreseeable future.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. We do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends on our common stock will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs and other factors. The declaration and payment of any future dividends on our common stock is currently prohibited by our revolving bank credit facility and senior secured note agreement and may be similarly restricted in the future.

Item 1B. Unresolved Staff Comments.

On December 30, 2008, we received a comment letter from the staff of the SEC (the "Staff") relating to our Form 10-K for the year ended December 31, 2007, our Form 10-Q for the quarter ended September 30, 2008, and our definitive proxy statement for our 2008 annual meeting of shareholders. We responded to this comment letter on January 21, 2009. After receiving an oral request from the Staff for a draft version of certain disclosures described in our original response, we supplemented that response on February 11, 2009.

We received a response from the Staff on February 24, 2009. Among other things, the Staff has requested additional production and reserves data from us relating to the proved undeveloped wells we drilled in 2007 and 2008 and the production forecasted in our 2006 year-end reserves report. We intend to cooperate with the Staff's request and hope to resolve the Staff's comments expeditiously. See "Item 1A Risk Factors—Risks Related to GMX—*We recently received comments from the SEC staff in connection with the staff's routine review of our filing. The SEC's review is not yet complete, and we may be required to make changes, including lowering the amount of reported reserves, to our filings in order to respond to the SEC staff's comments.*"

Item 2. Properties.

The information required by Item 2 is contained in Item 1—Business.

Item 3. Legal Proceedings.

None.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2008.

PART II

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

Common Stock

The high and low sales prices for our common stock as listed on The NASDAQ Global Select Market as applicable during the periods described below were as follows:

	High	Low
Year Ended December 31, 2007		
First Quarter	$38.38	$28.35
Second Quarter	40.70	30.55
Third Quarter	36.78	30.00
Fourth Quarter	40.04	30.52
Year Ended December 31, 2008		
First Quarter	$35.22	$23.65
Second Quarter	76.89	34.09
Third Quarter	88.35	40.74
Fourth Quarter	47.91	16.84

As of January 31, 2009, there were 80 record owners of our common stock and an estimated 8,388 beneficial owners.

Dividend Policy

We have never declared or paid any cash dividends on our shares of common stock and do not anticipate paying any cash dividends on our shares of common stock in the foreseeable future. Currently, we intend to retain any future earnings for use in the operation and expansion of our business. Any future decision to pay cash dividends on our common stock will be at the discretion of our board of directors and will be dependent upon our financial condition, results of operations, capital requirements and other facts our board of directors may deem relevant. The declaration and payment of dividends is currently prohibited under the terms of our revolving bank credit facility and senior secured note agreement and may be similarly restricted in the future. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Revolving Bank Credit Facility and Other Debt.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes the number of outstanding options granted to employees and directors, as well as the number of securities remaining available for future issuance, under our equity compensation plans as of December 31, 2008.

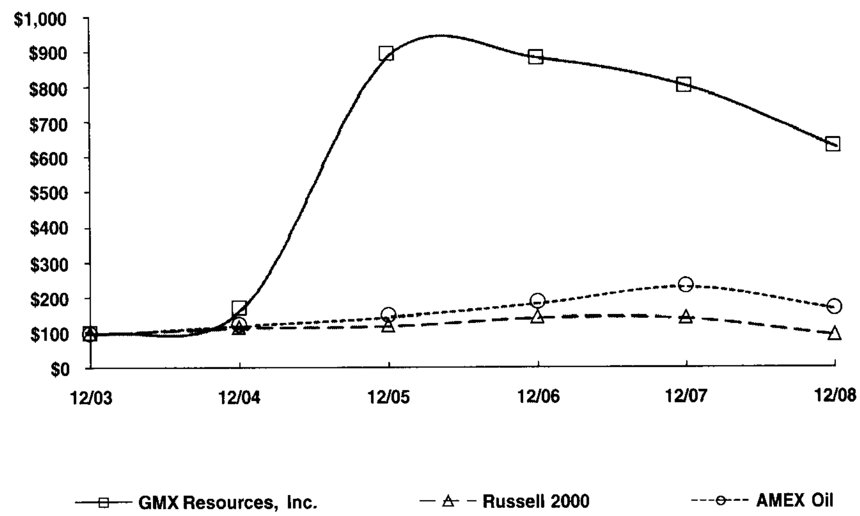
Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected at left)
Equity compensation plans approved by security holders	583,050	$30.16	689,250[1]

[1] Includes 670,751 shares that may be issued in the form of restricted stock or bonus stock grants under the Company's 2008 Long-Term Incentive Plan.

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder returns of our Common Stock during the five years ended December 31, 2008 with the cumulative total shareholder returns of the Russell 2000 Index and the AMEX Oil Index. The comparison assumes an investment of $100 on December 31, 2003 in each of our Common Stock, the Russell 2000 Index and the AMEX Oil Index and that any dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among GMX Resources, Inc., The Russell 2000 Index
And The AMEX Oil Index



* $100 invested on December 31, 2003 in stock & index-including reinvestment of dividends. Fiscal year ending December 31.

Recent Sales of Unregistered Equity Securities

None during 2008.

Purchases of Equity Securities

None during the fourth quarter of 2008.

Item 6. Selected Financial Data.

The following table presents a summary of our financial information for the periods indicated. It should be read in conjunction with our consolidated financial statements and related notes (beginning on page F-1 at the end of this report) and other financial information included herein.

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(in thousands, except share and per share data)				
Statement of Operations Data:					
Oil and natural gas sales	$ 7,690	$ 19,026	$ 31,882	$ 67,883	$ 125,736
Expenses:					
Lease operations	1,261	2,070	4,479	8,982	15,101
Production and severance taxes[1]	519	1,241	465	2,746	5,306
General and administrative	1,986	3,389	5,829	8,717	16,899
Depreciation, depletion and amortization	2,043	3,982	8,046	18,681	31,744
Impairment of oil and natural gas properties	—	—	—	—	151,629
Total expenses	5,809	10,682	18,819	39,126	220,679
Income (loss) from operations	1,881	8,344	13,063	28,757	(94,943)
Total non-operating income (expense)	(415)	24	(673)	(3,862)	(11,750)
Income (loss) before income taxes	1,466	8,368	12,390	24,895	(106,693)
Provision (benefit) for income taxes	24	1,212	3,415	8,010	(24,980)
Net income (loss)	1,442	7,156	8,975	16,885	(81,713)
Preferred stock dividends	—	—	1,799	4,625	4,625
Net income (loss) applicable to common stock	$ 1,442	$ 7,156	$ 7,176	$ 12,260	$ (86,338)
Net income (loss) per share—basic	$ .19	$ .81	$ .65	$ .94	$ (6.07)
Net income (loss) per share—diluted	$ .19	$ .79	$ .64	$ .93	$ (5.66)
Weighted average common shares—basic	7,396,880	8,797,529	11,120,204	13,075,560	14,216,466
Weighted average common shares—diluted	7,491,778	9,102,181	11,283,265	13,208,746	15,255,239
Statement of Cash Flows Data:					
Cash provided by operating activities	$ 3,684	$ 16,323	$ 38,333	$ 52,445	$ 87,811
Cash used in investing activities	(8,878)	(39,549)	(130,573)	(194,998)	(322,934)
Cash provided by financing activities	5,419	24,756	94,807	143,500	235,932
Balance Sheet Data (at end of period):					
Oil and natural gas properties, net	$ 35,957	$ 58,927	$ 157,300	$ 320,955	$ 433,114
Total assets	40,991	81,103	210,322	395,340	577,852
Long-term debt, including current portion	3,762	1,756	41,820	125,734	236,523
Shareholders' equity	32,407	61,225	131,481	208,926	277,417

[1] Production and severance taxes in 2006, 2007, and 2008 reflect severance tax refunds of $1.4 million, $518,000, and $1.2 million, respectively, received or accrued during the year.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation.

Summary Operating and Reserve Data

The following table presents an unaudited summary of certain operating and oil and natural gas reserve data for the periods indicated.

	Year Ended December 31,				
	2004	2005	2006	2007	2008
Production:					
Oil (MBbls)	30	48	69	127	190
Natural gas (MMcf)	1,049	1,930	3,915	7,974	11,777
Gas equivalent (MMcfe)	1,231	2,220	4,327	8,735	12,918
Average daily (MMcfe)	3.37	6.08	11.9	23.9	35.3
Average Sales Price:					
Oil (per Bbl)					
Wellhead price	$40.83	$53.35	$63.22	$ 71.08	$ 99.16
Effect of hedges	—	—	—	(1.97)	(10.19)
Total	$40.83	$53.35	$63.22	$ 69.11	$ 88.97
Natural gas (per Mcf)					
Wellhead price	$ 6.15	$ 8.52	$ 6.79	$ 7.00	$ 9.50
Effect of hedges	—	—	0.24	0.41	(0.26)
Total	$ 6.15	$ 8.52	$ 7.03	$ 7.41	$ 9.24
Average sales price (per Mcfe)	$ 6.25	$ 8.57	$ 7.37	$ 7.77	$ 9.73
Operating and Overhead Costs (per Mcfe):					
Lease operating expenses	$ 1.03	$ .93	$ 1.04	$ 1.03	$ 1.17
Production and severance taxes	.42	.56	.11	.31	.41
General and administrative	1.61	1.53	1.35	1.00	1.31
Total	$ 3.06	$ 3.02	$ 2.50	$ 2.34	$ 2.89
Cash Operating Margin (per Mcfe)	$ 3.19	$ 5.55	$ 4.87	$ 5.43	$ 6.84
Other (per Mcfe):					
Depreciation, depletion and amortization—oil and natural gas production	$ 1.28	$ 1.58	$ 1.59	$ 1.88	$ 2.08
Estimated Net Proved Reserves (as of period-end):					
Natural gas (Bcf)	56.9	150.0	236.9	406.3	435.3
Oil (MMbls)	1.2	2.0	2.7	4.7	5.0
Total (Bcfe)	64.3	161.7	253.0	434.5	465.3
Estimated Future Net Revenues ($MM)[(1)(2)]	$211.3	$692.9	$519.5	$1,896.3	$2,586.6
Present Value ($MM)[(1)(2)]	$ 82.0	$245.0	$173.3	$ 592.8	$ 280.7
Standardized measure of discounted future net cash flows ($MM)[(3)]	$ 63.3	$185.5	$134.4	$ 427.7	$ 228.8

(1) See "Item 1 Business—Certain Technical Terms."

(2) The prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as of period end. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. See "Item 1 Business—Reserves."

(3) The standardized measure of discounted future net cash flows give effect to federal and state income taxes attributable to estimated future net revenues. See "Note L—Supplemental Information on Oil and Natural Gas Operations."

Overview

We are an independent oil and gas company engaged in the exploration, development and production of oil and natural gas from the Haynesville/Bossier Shale and Cotton Valley Sands in our core area, the Sabine Uplift of the Carthage, North Field of Harrison and Panola counties of East Texas. We consider and report all of our operations as one segment because our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined in Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 131, *Disclosures about Segments of an Enterprise and Related Information.*

Our strategy is to grow shareholder value through Haynesville/Bossier Shale horizontal well development as well as Cotton Valley Sand vertical wells, to continue acreage acquisitions, to focus on operational growth in and around our core area, and to convert our natural gas reserves to proved reserves, while maintaining balanced prudent financial management. To date, we have experienced a 100% success rate and have maintained low finding and development costs while primarily drilling Cotton Valley Sand vertical wells. Late in the second quarter of 2008, we switched our strategy from developing the Cotton Valley Sands with vertical wells to the development of the Haynesville/Bossier Shale with horizontal wells due to the strong economic profile estimated to be associated with this play.

Results of Operations—Year ended December 31, 2008 Compared to Year ended December 31, 2007

Oil and Natural Gas Sales. Oil and natural gas sales in the year ended December 31, 2008 increased 85% to $125.7 million compared to the year ended December 31, 2007. Of the increase, 48% is due to higher natural gas and oil production and 25% to an increase in natural gas and oil prices. The average prices per barrel of oil and mcf of natural gas received in the year ended December 31, 2008 were $88.97 and $9.24, respectively, compared to $69.11 and $7.41, respectively, in the year ended December 31, 2007. Production of oil increased to 190 MBbls compared to 127 MBbls for 2007. Natural gas production increased to 11,777 MMcf for 2008 compared to 7,974 MMcf for the year ended December 31, 2007, an increase of 48%.

In the year ended December 31, 2008, as a result of hedging activities, we recognized a decrease in oil and natural gas sales of $5 million, compared to an increase in oil and natural gas sales of $3 million in the year ended December 31, 2007. In the year ended December 31, 2008, hedging reduced the average natural gas and oil sales price by $0.26 per Mcf and $10.19 per Bbl compared to an increase in natural gas sales price of $0.41 per Mcf and a decrease in oil sales price by $1.97 per Bbl in the year ended December 31, 2007.

Lease Operations. Lease operations expense increased $6.1 million in the year ended December 31, 2008 to $15.1 million , a 68% increase compared to the year ended December 31, 2007. Increased expense resulted from a greater number of producing wells in addition to maintenance expenses for the Company's growing field operations. Lease operations expense on an equivalent unit of production basis was $1.17 per Mcfe in the year ended December 31, 2008 compared to $1.03 per Mcfe for the year ended December 31, 2007.

Production and Severance Taxes. Production and severance taxes increased 93% to $5.3 million in the year ended December 31, 2008 compared to $2.7 million in the year ended December 31, 2007. Production and severance taxes are assessed on the value of the oil and natural gas produced. The above increase resulted from higher oil and natural gas sales described above offset by severance tax refunds of approximately $1.2 million recorded in 2008. A growing number of wells with natural gas production are exempt from severance taxes or have reduced severance tax rates. We recognized severance tax refunds of approximately $518,000 in 2007. Upon approval from the State of Texas, certain wells are exempt from severance taxes or eligible for a reduced severance tax rate for a period of ten years.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $13 million to $31.7 million in the year ended December 31, 2008, up 70% from the year ended December 31, 2007. This increase is due to higher production levels and higher costs. The oil and gas properties depreciation, depletion and amortization rate per equivalent unit of production was $2.08 per Mcfe in the year ended December 31, 2008 compared to $1.88 per Mcfe in the year ended December 31, 2007. The depletion rate increase was largely the result of lower oil and natural gas prices reducing the economic lives and reserves on our wells which resulted in our oil and natural gas properties being amortized over a smaller reserve base than if reserves were calculated at higher prices. As a result of lower oil and gas prices, the Company recognized an impairment charge on oil and gas properties of $151.6 million. The Company may be required to recognize additional impairment charges in future reporting periods if market prices for oil and gas continue to decline.

General and Administrative Expense. General and administrative expense for the year ended December 31, 2008 was $16.9 million compared to $8.7 million for the year ended December 31, 2007, an increase of 94%. The increase of $8.2 million was largely the result of hiring additional administrative and supervisory personnel to manage our growth and compensation increases implemented on July 1, 2008 to align our compensation more closely with our peers. Approximately $3.1 million of the general and administrative expenses was related to non-cash compensation expense compared to $1.6 million in 2007. Additionally, we recorded a $748,000 charge to bad debt expense related to our estimated exposure from a bankruptcy filed by one of our oil purchasers. General and administrative expense per equivalent unit of production was $1.31 per Mcfe for the year ended December 31, 2008 compared to $1.00 per Mcfe for the comparable period in 2007. Excluding the charge to bad debt expense, general and administrative expense on a per unit of production would have been $1.11 per Mcfe for the year-ended 2008. Longer term, general and administrative costs should decline on a per unit basis as our production increases from the Haynesville/Bossier development.

Interest. Interest expense for the year ended December 31, 2008 was $11,681,000 compared to $4,088,000 for the year ended December 31, 2007. This increase is due to a greater amount of outstanding debt during 2008.

Income Taxes. Income tax for 2008 was a benefit of $25 million as compared to an expense of $8 million in 2007. The effective tax rates for 2007 and 2008 were 32% and 23%, respectively. The decrease in the effective tax rate in 2008 was due to $11.5 million of deferred tax expense relating to a valuation allowance established for Federal net operating loss carryforwards that reduced our tax benefit. Excluding the deferred tax expense for the valuation allowance, our effective income tax would have been approximately 34%.

Results of Operations for the Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Oil and Natural Gas Sales. Oil and natural gas sales in the year ended December 31, 2007 increased 113% to $67.9 million compared to the year ended December 31, 2006, due to an increase of 102% in production and a 5% increase in the average oil and natural gas price. The average price per barrel of oil and mcf of gas received in 2007 was $69.11 and $7.41, respectively, compared to $63.22 and $7.03 in the year of 2006. Oil production for 2007 increased 58 MBbls to 127 MBbls compared to 2006. Gas production increased to 7,974 MMcf compared to 3,915 MMcf for the year of 2006, an increase of 104%. Increased production in 2007 resulted from drilling and completing new wells during the year. As a result of hedging activities, additional oil and natural gas sales of $3.0 million and $940,000 were recognized for 2007 and 2006, respectively. The hedging activities increased the average Mcfe sales price by $0.35 per Mcfe and $0.22 per Mcfe for the year ended 2007 and 2006, respectively.

Lease Operations. Lease operations expense increased $4.5 million in 2007 to $9.0 million, a 101% increase compared to 2006. Increased expenses resulted from re-works of wells and additional costs to operate new wells. Lease operations expense on an equivalent unit of production basis was $1.03 per Mcfe in 2007 compared to $1.04 per Mcfe for 2006.

Production and Severance Taxes. Production and severance taxes increased 490% to $2.7 million in 2007 compared to $465,000 in 2006. Production and severance taxes are assessed on the value of the oil and natural gas produced. The increase in production and severance taxes in 2007 is due to severance tax refunds of $1.4

million that were received or accrued during 2006. During 2006, severance tax refunds of $518,000 were received or accrued during the year. Upon approval by the State of Texas, certain wells are exempt from severance taxes for a period of ten years and this will reduce our expense going forward.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $10.6 million to $18.7 million in 2007, up 132% from 2006. This increase is due primarily to an increase in production for 2007. The oil and natural gas depreciation, depletion and amortization rate per equivalent unit of production was $1.88 per Mcfe in 2007 compared to $1.59 per Mcfe in 2006. An increase in drilling and completion costs in the field were the primary reason for increase.

Interest. Interest expense for 2007 was $4.1 million compared to $824,000 for 2006. This increase is primarily attributable to the increased amount of debt outstanding during 2007.

General and Administrative Expense. General and administrative expense for 2007 was $8.7 million compared to $5.8 million for 2006, an increase of 50%. This increase of $2.9 million was the result of increases in staff and related expenses necessary to operate at higher levels of drilling and production. Non-cash stock compensation expense increased $910,000 from $662,000 in 2006 to $1.6 million in 2007. General and administrative expense per equivalent unit of production was $1.00 per Mcfe for 2007 compared to $1.35 per Mcfe for 2006, reflecting improved efficiency levels.

Income Taxes. Income tax for 2007 was $8.0 million as compared to $3.4 million in 2006. The effective tax rates for 2006 and 2007 were 28% and 32%, respectively. The increase in the effective tax rate in 2007 is due primarily to the increase in the deferred tax liability associated with the difference between the financial carrying value of oil and natural gas properties and other property and equipment and the associated tax basis.

Net Income and Net Income per Share

Net Income and Net Income Per Share—Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. For the year ended December 31, 2008 and 2007, we reported net loss of $81.7 million and net income of $16.9 million, respectively. Excluding the impairment charge of $151.6 million ($100.1 million after income taxes) related to our oil and natural gas properties and a non-cash charge to deferred income taxes for a valuation allowance on our net operating loss carryforward of $11.5 million, we would have reported net income of $29.9 million for the year ended December 31, 2008, an increase of 77% compared to the year ended December 31, 2007. Net loss per basic and fully diluted share was $6.07 and $5.66 respectively, year ended 2008 compared to net income per basic and fully diluted share of $0.94 and $0.93 per basic and fully diluted share for 2007. Excluding the impairment charge related to our oil and natural gas properties and the valuation allowance on our net operating loss carryforward, net income per basic and fully diluted share would have been $1.77 and $1.65. Weighted average fully-diluted shares outstanding increased by 15% from 13,208,746 shares in 2007 to 15,255,239 shares in 2008.

We recognized additional dilutive shares of 873,870 for the year ended December 31, 2008, respectively, from the February 2008 issuance of net share settlement 5.00% Convertible Senior Notes due 2013. The dilutive effect of the convertible notes varies based on our stock price and for purposes of computing dilutive shares outstanding was based on the average stock price for the year ended December 31, 2008 of $42.06. The number of shares issuable increases as our common stock price increases and is finally determined based on the volume weighted average stock price for a specified 60-day measurement period ending on or about the actual conversion date.

Net Income and Net Income Per Share—Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. For 2007, we reported net income after preferred stock dividends of $12.3 million compared to $7.2 million for 2006. Net income per basic and fully diluted share was $0.94 and $0.93, respectively, in 2007 compared to $0.65 and $0.64 in 2006, respectively. Weighted average fully-diluted shares outstanding increased by 17% from 11,283,265 in 2006 to 13,208,746 in 2007.

Capital Resources and Liquidity

Our business is capital intensive. Our ability to grow our reserve base is dependent upon our ability to obtain outside capital and generate cash flows from operating activities to fund our drilling and capital expenditures. Our cash flows from operating activities are substantially dependent upon oil and natural gas prices, and significant decreases in market prices of oil or natural gas could result in reductions of cash flow and affect our drilling and capital expenditure plan. To mitigate a portion of our exposure to fluctuations in commodity prices, we have entered into oil and natural gas swaps, collars, and puts.

We continually review our drilling and capital expenditure plans and may change the amount we spend based on industry conditions and the availability of capital. We believe our cash flow from operating activities and our availability under our revolving bank credit facility ($110 million at December 31, 2008) are sufficient to fund our 2009 planned oil and gas capital expenditure program of $220 million. In the event natural gas prices remain at their current depressed levels or our capital expenditures exceed $220 million, we may not be able to increase our borrowing base under our revolving bank credit facility to fund a potential shortfall. While the annual increase in the available borrowing base we received during 2008 was $100 million, there can be no assurance that we will continue to successfully grow the available borrowing base in 2009 due to a number of potential risk factors that could adversely affect future borrowing base availability including, among other factors, a continued decline in commodity prices, and/or diminished credit availability from commercial banks.

In that event, we may be required to reduce or defer part of our 2009 capital expenditure program or seek additional capital through the issuance of additional long-term debt or equity. During 2008, we were successful in raising $266 million in additional capital by issuing $125 million of 5.00% Convertible Senior Notes due 2013 and 2,000,000 shares of common stock. However, the recent worldwide financial and credit crisis has adversely affected the ability of many companies to access the debt and equity markets. To the extent we determine to raise additional funds through the issuance of additional long-term debt or equity, any such decreased ability to obtain financing could adversely affect our capability to continue with our expected business plan.

Cash Flow—Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. In 2008, we had a positive cash flow from operating activities of $87.8 million as a result of increased production volume and higher oil and natural gas prices during 2008. Our cash flow from operating activities in 2007 was $52.4 million. Cash flow from operating activities before changes in operating assets and liabilities and after preferred stock dividends was $75.6 million compared to $40.8 million in 2007. This resulted from an 85% increase in oil and natural gas sales in 2008. We received a net $235.9 million in cash from financing activities in 2008 compared to 2007 amounts of $143.5 million. The cash flow from financing activities in 2008 was primarily from the sale of common stock of $134.7 million, issuance of 5.00% Convertible Senior Notes of $125.0 million and additional debt under our revolving bank credit facility. The cash inflow in 2007 from financing activities primarily resulted from the sale of common stock, private placement of Senior Secured Subordinated Notes and additional debt under our revolving bank credit facility.

Cash Flow—Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. In 2007, we had a positive cash flow from operating activities of $52.4 million as a result of increased production volume during 2007. Our cash flow from operating activities in 2006 was $38.3 million. Cash flow from operating activities before changes in operating assets and liabilities was $45.4 million compared to $21.1 million in 2006. This resulted from a 113% increase in oil and natural gas sales in 2007. We received a net $143.5 million in cash from financing activities in 2007 compared to 2006 amounts of $94.8 million. The cash flow from financing activities in 2007 was primarily from the sale of common stock of $65.7 million, private placement of Senior Secured Subordinated notes of $30 million and additional debt under our revolving bank credit facility. The cash inflow in 2006 from financing activities primarily resulted from the sale of preferred stock, common stock and additional debt under our revolving bank credit facility.

Revolving Bank Credit Facility and Other Debt

Revolving Bank Credit Facility. We have a secured revolving bank credit facility, which matures on July 15, 2011 and provides for a line of credit of up to $250 million (the "commitment"), subject to a borrowing base which is based on a periodic evaluation of oil and gas reserves ("borrowing base"). The amount of credit available at any one time under the credit facility is the lesser of the borrowing base or the amount of the commitment.

The loan bears interest at the rate elected by us of either the prime rate as published in *The Wall Street Journal* (payable monthly) or the LIBO rate plus a margin ranging from 1.75% to 2.25% based on the amount of the loan outstanding in relation to the borrowing base for a period of one, two or three months (payable at the end of such period). Principal is payable voluntarily by us or is required to be paid (i) if the loan amount exceeds the borrowing base; (ii) if the Lender elects to require periodic payments as a part of a borrowing base re-determination; and (iii) at the maturity date of July 15, 2011. We are obligated to pay a facility fee equal to 0.25% per year of the unused portion of the borrowing base payable quarterly.

The regular borrowing base has been adjusted from time to time and was $190 million at December 31, 2008. The loan is secured by a first mortgage on substantially all of our oil and natural gas properties, a pledge of our ownership of the stock of our subsidiaries, a guaranty from our subsidiaries and a security interest in all of the assets of our subsidiaries. The loan agreement was amended in February 2008 to permit the sale of our 5.00% Convertible Senior Notes due 2013.

In addition to customary reporting and compliance requirements, the principal covenants, as amended as of December 31, 2008, under the revolving bank credit facility are:

- Maintain a current ratio (as defined in the loan agreement) of not less than 1 to 1;
- Maintain a minimum net worth of $210 million as of June 12, 2008 adjusted quarterly to add 50% of our positive net income for each quarter and 100% of net proceeds of equity offerings. For purposes of this covenant, the non-cash effects, if any, of hedging agreements pursuant to Financial Accounting Standards Board Rule No. 133 (Accounting for Derivative Instruments and Hedging Activities), and of ceiling test write-downs pursuant to Regulation S-X 4-10 of the SEC will not be included;
- Maintain on a quarterly basis a rolling four quarter ratio of EBITDA to cash interest expense and preferred dividends of not less than 3 to 1;
- Maintain a hedging program on mutually acceptable terms whenever the loan amount outstanding exceeds 75% of the borrowing base;
- Pay all accounts payable within 60 days of the due date other than those being contested in good faith;
- Not incur any other debt other than up to $30 million of our Secured Notes, our Series B Preferred Stock and our $125 million of 5.00% Convertible Senior Notes, due 2013;
- Not permit any liens other than those permitted by the loan agreement;
- Not make any investments, loans or advances other than as permitted by the loan agreement, which includes permitted investment in Diamond Blue Drilling for no more than three drilling rigs;
- Not engage in any mergers or consolidations or sales of all or substantially all of our assets;
- Not pay any dividends on common stock or make any other distributions with respect to our stock, including stock repurchases;
- Not permit Ken L. Kenworthy Jr. to cease being our chief executive officer, other than by reason of his death or disability if we name a successor acceptable to the lenders within four months;
- Not permit a person or group (other than existing management) to acquire more than 50% of the outstanding common stock or otherwise suffer a change in control; and
- Not to make any cash payments in respect of interest or on account of the conversion, purchase, acquisition or termination of our 5.00% Convertible Senior Notes due 2013 unless no event of default under the loan agreement exists or the payment would not result in such a default and the borrowing base has not been exceeded.

As of December 31, 2008, we were in compliance with all financial covenants under the revolving bank credit facility. The minimum net worth financial covenant for which the bank credit facility was amended effective December 31, 2008 to amend the calculation to exclude the non-cash effects of ceiling test write-downs pursuant to regulations S-X Rule 4-10 of the Securities and Exchange Commission.

In December 2007, we entered into an agreement to grant a temporary increase in the borrowing base of $30 million (the "Bridge Loan") from the existing $90 million to $120 million until the earlier of the completion of additional financing or June 30, 2008. The Bridge Loan bore interest at a rate that was 2.25% higher per annum than our other borrowings under the normal borrowing base, and the unused facility fee was 0.25% higher than the 0.25% fee for the normal borrowing base. In connection with the amendment, the Company paid an upfront commitment and arrangement fee of 2.5% of the Bridge Loan, or $750,000. Upon closing of the issuance of our $125 million 5.00% Convertible Senior Notes in February 2008, we repaid the Bridge Loan.

As of December 31, 2008, we had $80.0 million outstanding under the revolving bank credit facility. We will borrow under the revolving bank credit facility up to the current borrowing base, $190 million, to fund planned capital expenditures and for other general corporate purposes. Our lending bank group consists of Capital One, N.A., BNP Paribas, Union Bank of California, N.A., Compass Bank, and Fortis Capital Corp.

Senior Subordinated Secured Notes. In July 2007, we entered into a Note Purchase Agreement ("Note Agreement") with The Prudential Insurance Company of America ("Prudential") providing for the issuance and sale from time to time of up to $100 million in Senior Subordinated Secured Notes (the "Secured Notes") and sold to Prudential an initial tranche of $30 million of 7.58% Series A fixed rate notes due July 31, 2012 with interest payable quarterly. Proceeds from the sale of the Secured Notes were used for general corporate purposes including additional funding of drilling and development costs in the Cotton Valley Sands in East Texas. The Secured Notes are secured by a second lien on all of the assets of the Company and its subsidiaries and are guaranteed by the Company's subsidiaries, subject to the terms of an Intercreditor Agreement between our senior lenders and the collateral agent for the Noteholders, including Prudential. We amended the Note Agreement in February 2008 in connection with the sale of our 5.00% Convertible Senior Notes due 2013. The principal covenants contained in the Note Agreement, in addition to customary covenants for similar transactions are:

- The ratio of Adjusted PV10 (as defined in the Note Agreement based on prescribed pricing and other parameters, which prescribes prices for oil production to be the lesser of the NYMEX strip price or $50.00 and for gas production of a fixed $6.50 per mcf) to Total Debt at the end of each quarter may not be less than 1.5 to 1;
- The ratio of Total Debt to EBITDA for the immediately preceding four quarters may not be greater than 4.0 to 1;
- The ratio of EBITDA to cash interest expense (which is defined to include dividends on outstanding preferred stock) for the immediately preceding four quarters may not be less than 2.5 to 1;
- Tangible net worth may not be less than $165 million plus 50% of net income commencing with the fiscal quarter ending March 31, 2009 and 100% of net cash proceeds from the sale of equity securities after December 31, 2008. For purposes of this covenant, the non-cash effects, if any, of Swaps, as defined in the Note Agreement, pursuant to Financial Accounting Standards Board Rule No. 133 (Accounting for Derivative Instruments and Hedging Activities) and of ceiling test write-downs (after January 1, 2009) will not be included;
- We may not incur senior bank debt in excess of $200 million without the consent of the Noteholders;
- Neither the Company nor any subsidiaries may incur any liens other than under the Company's revolving bank credit facility and the Secured Notes, other than certain permitted liens;
- We may not issue Secured Notes in excess of the Series A Notes without the consent of Prudential and pro forma compliance with the financial covenants. Additional debt would also require the consent of our lenders under the revolving bank credit facility;

- We may not incur any other indebtedness without pro forma compliance with the financial covenants, and without subordination terms satisfactory to Prudential, which additional debt would also require the consent of our lenders under the revolving bank credit facility. In this regard, Prudential agreed that we could issue our 5.00% Convertible Senior Notes due 2013; provided no cash payments in respect of interest on such notes or on account of the conversion, purchase, acquisition, cancellation or termination of such notes may be made by us unless after giving effect thereto (a) no event of default under the Note Agreement exists, and (b) no event exists that, with the giving of notice, the passage of time or the satisfaction of other conditions precedent, would be an event of default under the Note Agreement;
- We are required to maintain commodity price hedges with a term of not greater than three years and with notional amounts (i) greater than 25% of projected production for the following twelve months from proved developed producing reserves and (ii) not more than the lesser of (a) 75% of projected production for the following 12 months from all proved reserves or (b) 90% of projected production for the following twelve months from proved developed reserves; and
- We may not issue any additional redeemable preferred stock without the consent of Noteholders, which would also require the consent of our lenders under the revolving bank credit facility.

As of December 31, 2008, we were in compliance with all financial covenants except for the tangible net worth covenant for which we received a waiver. Subsequent to December 31, 2008, the tangible net worth covenant has been amended as described above.

In the event of a change in control, defined to be an acquisition of greater than 50% of our outstanding voting stock (other than an acquisition by a public company meeting specified financial requirements) or change in management (defined as Ken L. Kenworthy, Jr. not being the chief executive officer for any reason, except that upon Mr. Kenworthy's death or disability, we have the ability to avoid a change in management if we name a successor chief executive officer acceptable to Prudential within four months), the Company is required to give notice to the Noteholders and offer to repurchase the Subordinated Notes at the outstanding principal amount plus accrued interest plus, in the case of any fixed rate notes, including the Series A Notes, a yield maintenance amount.

5.00% Convertible Senior Notes Due 2013. In February 2008, we completed a $125 million private placement of 5.00% Convertible Senior Notes due 2013 (the "Convertible Notes"). Net proceeds of approximately $121 million were used to repay our revolving bank credit facility and the Bridge Loan. The Convertible Notes are governed by an indenture, dated as of February 15, 2008 (the "Indenture") between the Company and The Bank of New York Trust Company, N.A., as trustee (the "Trustee").

The Convertible Senior Notes bear interest at a rate of 5.00% per year, payable semiannually in arrears on February 1 and August 1 of each year, beginning August 1, 2008. The Convertible Notes mature on February 1, 2013, unless earlier converted or repurchased by us. Holders may convert their Convertible Notes at their option prior to the close of business on the business day immediately preceding November 1, 2012 only under the following circumstances:

- during any fiscal quarter commencing after March 31, 2008 if the last reported sale price of the common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter is greater than or equal to 130% of the applicable conversion price on each such trading day;
- during the five business-day period after any five consecutive trading-day period (the "measurement period") in which the trading price (as defined below) per $1,000 principal amount of Convertible Notes for each day of that measurement period was less than 98% of the product of the last reported sale price of our common stock and the applicable conversion rate on each such day;

- upon the occurrence of a corporate event pursuant to which: (1) we issue rights to all or substantially all of the holders of our common stock entitling them to purchase, for a period expiring within 60 days after the date of the distribution, shares of our common stock at a price below the average market price at the time, or (2) we distribute to all or substantially all of the holders of our common stock our assets, debt securities or rights to purchase our securities, if the distribution has a per share value in excess of 10% of the last reported sale price for our common stock at the time; or
- if: (1) a "person" or "group" within the meaning of Section 13(d) of the Exchange Act acquires more than 50% of our outstanding voting stock, (2) we consummate a recapitalization, reclassification or change of our common stock as a result of which our common stock would be converted into or exchanged for stock, other securities, other property or assets, (3) we consummate a share exchange, consolidation or merger pursuant to which our common stock will be converted into cash, securities or other property, (4) we consummate any sale, lease or other transfer in one transaction or a series of transactions of all or substantially all of our and our subsidiaries' consolidated assets to any person other than one of our subsidiaries, (5) continuing directors cease to constitute at least a majority of our board of directors, (6) our shareholders approve any plan or proposal for our liquidation or dissolution, or (7) our common stock ceases to be listed on a United States national or regional securities exchange (any of the events described in clauses (1) through (7), a "fundamental change").

On and after November 1, 2012 until the close of business on the business day immediately preceding the maturity date, holders may convert their Convertible Notes at any time, regardless of the foregoing circumstances.

Upon conversion, we will satisfy our conversion obligation by paying and delivering cash for the lesser of the principal amount or the conversion value, and, if the conversion value is in excess of the principal amount, by paying or delivering, at our option, cash and/or shares of our common stock for such excess. The conversion value is a daily value calculated on a proportionate basis for each day of a 60 trading-day observation period.

The conversion rate is initially 30.7692 shares of the Company's common stock per $1,000 principal amount of Convertible Notes (equivalent to a conversion price of approximately $32.50 per share of common stock). The conversion rate is subject to adjustment in some events but will not be adjusted for accrued interest. In addition, following any fundamental change that occurs prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its Notes in connection with such a fundamental change in certain circumstances. The increase in the conversion rate is determined based on a formula that takes into consideration our stock price at the time of the fundamental change (ranging from $25.00 to $150.00 per share) and the remaining time to maturity of the Convertible Notes. The increase in the conversion rate ranges from 0% to 30%, increasing as the stock price at the time of the fundamental change increases from $25.00 and declining as the remaining time to maturity of the Convertible Notes decreases.

We may not redeem the Convertible Notes prior to maturity. However, if we undergo a fundamental change, holders may require us to repurchase the Convertible Notes in whole or in part for cash at a price equal to 100% of the principal amount of the Notes to be repurchased plus any accrued and unpaid interest (including additional interest, if any) to, but excluding, the fundamental change repurchase date.

The Convertible Notes are senior unsecured obligations of the Company and rank equally in right of payment to all of the Company's other existing and future senior indebtedness. The Convertible Notes are effectively subordinated to all our secured indebtedness, including indebtedness under our revolving bank credit facility and our senior secured notes, to the extent of the value of our assets pledged as collateral for such indebtedness. The Convertible Notes are also effectively subordinated to all liabilities of our subsidiaries, including liabilities under any guarantees they have issued.

Share Lending Agreement

In February 2008, in connection with the offer and sale of the Convertible Notes, we entered into a share lending agreement (the "Share Lending Agreement") with an affiliate of Jefferies & Company, Inc. (the "share borrower") and Jefferies & Company, Inc., as collateral agent for the Company. Under this agreement, we will loan to the share borrower up to the maximum number of shares of our common stock underlying our Convertible Notes during a specified loan availability period. This maximum number of shares is initially 3,846,150 shares. We will receive a loan fee of $0.001 per share for each share of our common stock that we loan to the share borrower, payable at the time such shares are borrowed. The share borrower may borrow and re-borrow up to the maximum number of shares of our common stock during the loan availability period. We have loaned to the share borrower 3,440,000 shares as of December 31, 2008.

The share borrower's obligations under the Share Lending Agreement are unconditionally guaranteed by Jefferies Group, Inc., the ultimate parent company of the share borrower and Jefferies & Company, Inc. (the "guarantor"). If the guarantor receives a rating downgrade for its long term unsecured and unsubordinated debt below a specified level by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc. (or any substitute rating agency mutually agreed upon by the Company and the share borrower), or by either of such rating agencies in certain circumstances, the share borrower has agreed to post and maintain with Jefferies & Company, Inc., acting as collateral agent for the Company, collateral in the form of cash, government securities, certificates of deposit, high-grade commercial paper of U.S. issuers, letters of credit or money market shares with a market value at least equal to 100% of the market value of the shares of our common stock borrowed by the share borrower as security for the share borrower's obligation to return the borrowed shares to the Company pursuant to the Share Lending Agreement.

The loan availability period under the Share Lending Agreement commenced on the date of the Share Lending Agreement and will continue until the date that any of the following occurs:

- we notify the share borrower in writing of our intention to terminate the Share Lending Agreement at any time after the entire principal amount of the Notes ceases to be outstanding as a result of conversion, repurchase, at maturity or otherwise;
- we and the share borrower agree to terminate the Share Lending Agreement;
- we elect to terminate all of the outstanding loans upon a default by the share borrower under the Share Lending Agreement or by the guarantor under its guarantee, including a breach by the share borrower of any of its obligations or a breach in any material respect of any of the representations or covenants under the Share Lending Agreement or a breach by the guarantor of the guarantee, or the bankruptcy of the share borrower or the guarantor; or
- the share borrower elects to terminate all outstanding loans upon the bankruptcy of the Company.

Any shares we loan to the share borrower will be issued and outstanding for corporate law purposes, and accordingly, the holders of the borrowed shares will have all of the rights of a holder of a share of our outstanding common stock, including the right to vote the shares on all matters submitted to a vote of the Company's shareholders and the right to receive any dividends or other distributions that we may pay or make on our outstanding shares of common stock. However, under the Share Lending Agreement, the share borrower has agreed:

- not to vote any shares of the Company's common stock it has borrowed to the extent it owns such borrowed shares; and
- to pay to us an amount equal to any cash dividends that we pay on the borrowed shares.

In view of the contractual undertakings of the share borrower in the Share Lending Agreement, which have the effect of substantially eliminating the economic dilution that otherwise would result from the issuance of the borrowed shares, we believe that under U.S. generally accepted accounting principles currently in effect, the borrowed shares will not be considered outstanding for the purpose of computing and reporting our earnings per share.

2008 Common Stock Offering

In July 2008, we completed a public offering of 2,000,000 shares of our common stock for $70.50 per share. Net proceeds to us were approximately $134 million, which we used to fund drilling and development of our East Texas properties and for other general corporate purposes.

Working Capital

At December 31, 2008, we had a working capital deficit of $16.8 million. Including availability under our credit facility, our working capital as of December 31, 2008 would have been $93.2 million.

Commitments and Capital Expenditures

The following table reflects the Company's contractual obligations as of December 31, 2008.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-term debt	$235,000	$ —	$ 80,000	$155,000	$ —
Operating leases	2,947	828	1,237	882	—
Drilling contracts	129,429	17,024	86,286	26,119	—
Asset retirement obligations	6,049	587	108	—	5,354
75% PVOG financing[1]	1,523	61	105	89	1,268
Total	$374,948	$18,500	$167,736	$182,090	$6,622

(1) PVOG financing is payable out of 75% of revenues from the wells financed and repayment is based on estimated production which may vary from actual.

Other than obligations under our revolving bank credit facility, the Secured Notes, the Convertible Notes and the PVOG financing and operating leases, our commitments relate to capital expenditures for development of oil and natural gas properties. We will not enter into drilling or development commitments until such time as a source of funding for such commitments is known to be available, either through financing proceeds, internal cash flow, additional funding under our revolving bank credit facility or working capital. During 2008, we entered into three year contracts with H&P for four rigs to be delivered in 2009 to develop our Haynesville/ Bossier Shale acreage. The total three year commitment associated with these rigs is $129.4 million. We also entered into a two year contract with Unit Corporation for a drilling rig for a total potential commitment of $16.1 million. The contract is cancelable for a $2 million penalty.

2009 Guidance

We estimate first quarter 2009 production to be 2.8 Bcfe.

Critical Accounting Policies

The preparation of the consolidated financial statements requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of our accounting estimates and judgments which management believes are most significant in its application of generally accepted accounting principles used in the preparation of the consolidated financial statements.

Full Cost Calculations

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full-cost method. We follow the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, although this difference could change in periods of lower price environments that result in write-downs of our costs as described below.

The full cost method subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of properties that can be capitalized on the balance sheet. If our capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. Our discounted present value of estimated future net revenues from our proved oil and natural gas reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. There can be no assurance that significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property write-down. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of the full cost pool amortization.

The estimates of proved undeveloped reserve quantities and values are based on estimated future drilling which assumes that we will have the financing available to fund the estimated drilling costs. If we do not have such financing available at the time projected, the estimates of proved undeveloped reserve quantities and values will change.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than various industry long-term price forecasts. Therefore, oil and natural gas property write-downs that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions in the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and natural gas properties. Statement of Financial Accounting Standard ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*," requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. The related capitalized cost, including revisions thereto, is charged as an expense to the consolidated statement of operations.

Income Taxes

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and the net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not more likely than not, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

Derivative Instruments

SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" ("SFAS 133"), as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. Upon entering into a derivative contract, we may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, mark the contract to market through earnings. We document the relationship between the derivative instrument designated as a hedge and the hedged items, as well as our objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as cash flow hedges are linked to specific forecasted transactions. We assess at inception, and on an ongoing basis, whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting.

Changes in fair value of a qualifying cash flow hedge are recorded in accumulated other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the statement of operations, the fair value of the associated cash flow hedge is reclassified from accumulated other comprehensive income into earnings as a component of oil and gas sales. Ineffective portions of a cash flow hedge are recognized currently as a component of oil and gas sales. The changes in fair value of derivative instruments not qualifying or not designated as hedges are reported currently in the consolidated statement of operations as unrealized gains (losses) on derivatives, a component of non-operating income (expense). If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in accumulated other comprehensive income is recognized over the period anticipated in the original hedge transaction.

Oil and Gas Revenues

Oil and natural gas revenues are recognized when 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. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by others. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. We record any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

During the course of normal operations, the Company and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, cash settlements are made among the joint interest owners under a variety of arrangements. The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. There are no significant imbalances as of December 31, 2006, 2007 or 2008.

Other

See Note A to Consolidated Financial Statements for information related to other accounting and reporting policies.

Recently Issued Accounting Pronouncements

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

Off-Balance Sheet Arrangements

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

Price Risk Management

See Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

Forward-Looking Statements

All statements made in this document other than purely historical information are "forward looking statements" within the meaning of the federal securities laws. These statements reflect expectations and are based on historical operating trends, proved reserve positions and other currently available information. Forward looking statements include statements regarding future plans and objectives, future exploration and development expenditures and number and location of planned wells and statements regarding the quality of our properties and potential reserve and production levels. These statements may be preceded or followed by or otherwise include the words "believes," "expects," "anticipates," "intends," "continues," "plans," "estimates," "projects" or similar expressions or statements that events "will," "should," "could," "might" or "may" occur. Except as otherwise specifically indicated, these statements assume that no significant changes will occur in the operating environment for oil and natural gas properties and that there will be no material acquisitions or divestitures except as otherwise described.

The forward-looking statements in this report are subject to all the risks and uncertainties which are described in this document. We may also make material acquisitions or divestitures or enter into financing transactions. None of these events can be predicted with certainty and are not taken into consideration in the forward-looking statements.

For all of these reasons, actual results may vary materially from the forward looking statements and we cannot assure you that the assumptions used are necessarily the most likely. We will not necessarily update any forward looking statements to reflect events or circumstances occurring after the date the statement is made except as may be required by federal securities laws.

There are a number of risks that may affect our future operating results and financial condition. See "Item 1A. Risk Factors."

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Price Risk

We are subject to price fluctuations of natural gas and crude oil. Prices received for natural gas and crude oil are volatile due to factors beyond our control. Reductions in crude oil and natural gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis. Any reduction in reserves, including reductions due to lower prices, can reduce our borrowing base under our revolving bank credit facility and adversely affect our liquidity and our ability to obtain capital for our acquisition and development activities.

To mitigate a portion of our exposure to lower commodity prices, we enter into financial price risk management activities with respect to a portion of projected oil and natural gas production through financial price swaps and options. Our revolving bank credit facility requires us to maintain a hedging program on mutually acceptable terms whenever the loan amount outstanding exceeds 75% of the borrowing base. In addition, the note agreement for our Series A Notes requires us to hedge a certain portion of production.

For swap instruments, we receive a fixed price for our production and pay a variable price to the contract counterparty. The fixed-price payment and the floating price payment are netted, resulting in a net amount due to or from the counterparty. Collars contain a fixed floor price (long put option) and ceiling price (short call option). If the market price exceeds the ceiling price, we pay the difference between the market price and ceiling price. If the market price is less than the fixed floor price, we receive the difference between the fixed floor price and the market price. If the market price is between the ceiling and the fixed floor price, no payments are due from either party. Following is a summary of the outstanding oil and natural gas swaps and collars we have in place as of December 31, 2008:

Effective Date	Maturity Date	Average Notional Amount Per Month	Remaining Notional Amount as of December 31, 2008	Additional Put Option	Floor	Ceiling
Natural Gas (MMBtu):						
6/1/2008	12/31/2009	100,000	1,200,000		$ 9.50	$ 12.20
1/1/2008	12/31/2009	100,000	1,200,000		$ 7.50	$ 8.15
1/1/2009	3/1/2009	189,000	567,000	$5.00	$ 7.50	—
4/1/2009	12/31/2009	189,000	1,696,000		$ 7.50	$ 8.60
1/1/2009	12/31/2009	200,000	2,400,000		$ 7.50	$ 9.17
1/1/2009	12/31/2009	250,000	3,000,000		$ 6.50	— (3)
1/1/2010	12/31/2010	300,000	3,600,000		$ 7.50	$ 8.91
1/1/2010	12/31/2010	172,000	2,062,000	$5.00	$ 7.50	$ 9.05(1)(2)
1/1/2010	12/31/2010	25,000	300,000		—	$ 7.50(3)(4)
1/1/2011	12/31/2011	110,000	1,320,000		—	$ 7.50(2)
Oil (Bbls):						
1/1/2009	12/31/2009	5,000	60,000		$100.00	$134.00

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call (ceiling) establishes the maximum price that we will receive for the contracted commodity volumes. The purchased put (floor) establishes the minimum price that we will receive for the contracted volumes unless the market price for the commodity falls below the sold (lower or additional) put strike price, at which point the minimum price equals the reference price (i.e., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

(2) The sold put has an average notional amount per month of 115,000 MMBtus and is settled based on NYMEX.

(3) Derivative transaction is settled based on NYMEX. Unless indicated all other natural gas hedges are settled at Houston Ship Channel.

(4) Ceiling was subsequently raised to $8.50/MMbtu in January 2009.

Natural gas hedging contracts are settled against Inside FERC—Houston Ship Channel Index Price or NYMEX and all oil contracts are settled against NYMEX Light Sweet Crude. The Inside FERC—Houston Ship Channel Index Price and NYMEX Light Sweet Crude have historically have had a high degree of correlation with the actual prices received by the Company. The estimated fair value of our natural gas and oil swaps and options in effect at December 31, 2008 was an asset of $25.1 million, of which $21.3 million is classified as a current asset and $3.8 million is classified as a long-term asset. The long term asset is included in other assets at December 31, 2008. The asset at December 31, 2008, reflects the fact that the prices under our swaps and options contracts in the aggregate are higher than period end forward prices. The fair value of these contracts varies based on commodity prices. While we will not recognize the benefit from commodity prices in excess of our fixed prices, we mitigate the risk of lower prices.

Based on the monthly notional amount for natural gas in effect at December 31, 2008, a hypothetical $1.00 increase in natural gas prices would have decreased the fair value of our natural gas swaps and options by $9.9

million and a \$1.00 decrease in natural gas prices would increase the fair value of our natural gas swaps and options by \$10.2 million. Based on the monthly notional amount for oil in effect at December 31, 2008, a hypothetical \$1.00 increase in oil prices would have decreased the fair value of our oil swap by \$55,000 and a \$1.00 decrease in oil prices would increase the fair value of our oil swap by \$56,000 per month.

Interest Rate Risk

As of December 31, 2008, we had \$80 million of long-term debt outstanding under our revolving bank credit facility. The credit facility matures in July 2011 and is governed by a borrowing base calculation that is redetermined periodically. We have the option to elect interest at the prime rate as published in the Wall Street Journal (payable monthly) or the LIBO rate plus a margin ranging from 1.75% to 2.25% based on the amount of the loan outstanding in relation to the borrowing base for a period of one, two or three months (payable at the end of such period). As a result, our interest costs fluctuate based on short-term interest rates relating to our credit facility. Based on borrowings outstanding at December 31, 2008, a 100 basis point change in interest rates would change our interest expense by approximately \$800,000. We had no interest rate derivatives during 2008.

Our \$30 million of Secured Notes and \$125 million of Convertible Notes have fixed interest rates of 7.58% and 5.00%, respectively.

Item 8. Financial Statements and Supplementary Data.

Our consolidated financial statements are presented beginning on page F-1 found at the end of this report.

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

None.

Item 9A. Controls and Procedures.

Controls and Procedures

Our principal executive officer and principal financial officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2008. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide us with reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and is accumulated and communicated to our management, including our principal executive officer and principal financial officer, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosures. Based on that evaluation, our principal executive officer and principal financial officer have concluded that our current disclosure controls and procedures are effective to provide us with this reasonable assurance.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2008, no change occurred in our internal control over financial reporting that materially affected, or is likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we evaluated the effectiveness of the design and operation 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. Based on that evaluation, our chief executive officer and chief financial officer concluded that our internal control over financial reporting was effective as of December 31, 2008, as reflected in our report included in Item 8.

Smith, Carney & Co., p.c., our independent registered public accounting firm, audited internal control over financial reporting and, based on that audit, issued the report set forth in Item 8.

Certifications

Our chief executive and chief financial officers have completed the certifications required to be filed as an Exhibit to this Report (See Exhibits 31.1 and 31.2) relating to the design of our disclosure controls and procedures and the design of our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

In accordance with the provisions of General Instruction G(3), information required by Items 10 through 14 of Form 10-K is incorporated herein by reference to the Company's Proxy Statement for the Annual Meeting of Shareholders to be filed prior to April 30, 2009.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this report.

Financial Statements: See Index to Consolidated Financial Statements and Consolidated Financial Statement Schedule set forth on page F-1 of this report.

Exhibits: For a list of documents filed as exhibits to this report, see the Exhibit Index immediately preceding the Exhibits filed with this report.

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.

GMX RESOURCES INC.

Dated: February 27, 2009

By: /s/ JAMES A. MERRILL
James A. Merrill, Chief Financial Officer

Pursuant to the requirement of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ KEN L. KENWORTHY, JR. **Ken L. Kenworthy, Jr.**	President and Director (Principal Executive Officer)	February 27, 2009
/s/ JAMES A. MERRILL **James A. Merrill**	Chief Financial Officer (Principal Financial and Accounting Officer)	February 27, 2009
/s/ T. J. BOISMIER **T. J. Boismier**	Director	February 27, 2009
/s/ STEVEN CRAIG **Steven Craig**	Director	February 27, 2009
/s/ KEN L. KENWORTHY, SR. **Ken L. Kenworthy, Sr.**	Director	February 27, 2009
/s/ JON W. MCHUGH **Jon W. McHugh**	Director	February 27, 2009

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and
Stockholders of GMX Resources Inc. and Subsidiaries

We have audited the accompanying balance sheets of GMX Resources Inc. and Subsidiaries as of December 31, 2008 and 2007, and the related statements of income, stockholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2008. We also have audited GMX Resources Inc. and Subsidiaries 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 (COSO). GMX Resources Inc.'s management is responsible for these financial statements, 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 Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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, the financial statements referred to above present fairly, in all material respects, the financial position of GMX Resources Inc. and Subsidiaries as of December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, GMX Resources Inc. and Subsidiaries maintained, in all material respects, effective 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 (COSO).

/s/ Smith, Carney & Co., p.c.

Smith, Carney & Co., p.c.

Oklahoma City, Oklahoma
February 27, 2009

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13(a)-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, our management has conducted an assessment, including testing, using the criteria in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Our system of internal control over financial reporting is 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our 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.

Based on the assessment, our management has concluded that we maintained effective internal control over financial reporting as of December 31, 2008, based on criteria in *Internal Control—Integrated Framework* issued by COSO. Our internal control over financial reporting as of December 31, 2008, has been audited by Smith, Carney & Co., p.c., an independent registered public accounting firm, as stated in their report which is included herein.

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Our disclosure controls and procedures are designed to provide us with reasonable assurance of achieving their objectives. Our management, including our principal executive officer and principal financial officer, has concluded that our disclosure controls and procedures are effective to provide us with this reasonable assurance.

GMX Resources Inc. and Subsidiaries
Consolidated Balance Sheets
(dollars in thousands, except share data)

	December 31, 2007	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,907	$ 6,716
Accounts receivable—interest owners	906	576
Accounts receivable—oil and natural gas revenues, net	10,258	9,145
Derivative instruments	—	21,325
Inventories	62	691
Prepaid expenses and deposits	1,720	2,040
Total current assets	18,853	40,493
OIL AND NATURAL GAS PROPERTIES, BASED ON THE FULL COST METHOD		
Properties being amortized	352,069	608,865
Properties not subject to amortization	2,143	36,034
Less accumulated depreciation, depletion, and amortization	(33,257)	(211,785)
	320,955	433,114
PROPERTY AND EQUIPMENT, AT COST, NET	54,957	85,284
DEFERRED INCOME TAXES	—	11,519
OTHER ASSETS	575	7,442
TOTAL ASSETS	$395,340	$ 577,852
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 34,941	$ 35,599
Accrued expenses	2,911	6,089
Accrued interest	867	3,290
Revenue distributions payable	3,667	5,293
Derivative instruments	1,720	—
Deferred income tax	—	6,996
Current maturities of long-term debt	4,321	61
Total current liabilities	48,427	57,328
LONG-TERM DEBT, LESS CURRENT MATURITIES	121,413	236,462
OTHER LIABILITIES	4,649	6,645
DEFERRED INCOME TAXES	11,925	—
SHAREHOLDERS' EQUITY:		
Preferred stock, par value $.001 per share, 10,000,000 shares authorized:		
Series A Junior Participating Preferred Stock 25,000 shares authorized, none issued and outstanding	—	—
9.25% Series B Cumulative Preferred Stock, 3,000,000 Shares authorized, 2,000,000 shares issued and outstanding (aggregate liquidation preference $50,000,000)	2	2
Common stock, par value $.001 per share—authorized 50,000,000 shares issued and outstanding 13,267,886 shares in 2007 and 18,794,691 shares in 2008	13	19
Additional paid-in capital	180,543	318,752
Retained earnings	29,686	(56,652)
Accumulated other comprehensive income, net of taxes	(1,318)	15,296
Total shareholders' equity	208,926	277,417
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$395,340	$ 577,852

See accompanying notes to consolidated financial statements.

GMX Resources Inc. And Subsidiaries
Consolidated Statements of Operations
(dollars in thousands, except share and per share data)

	Year Ended December 31,		
	2006	2007	2008
OIL AND GAS SALES	$ 31,882	$ 67,883	$ 125,736
EXPENSES:			
Lease operations	4,479	8,982	15,101
Production and severance taxes	465	2,746	5,306
Depreciation, depletion, and amortization	8,046	18,681	31,744
Impairment of oil and natural gas properties	—	—	151,629
General and administrative	5,829	8,717	16,899
Total expenses	18,819	39,126	220,679
Income (loss) from operations	13,063	28,757	(94,943)
NON-OPERATING INCOME (EXPENSES):			
Interest expense	(824)	(4,088)	(11,681)
Interest and other income	151	226	285
Unrealized loss on derivatives	—	—	(354)
Total non-operating expense	(673)	(3,862)	(11,750)
Income (loss) before income taxes	12,390	24,895	(106,693)
(PROVISION) BENEFIT FOR INCOME TAXES	(3,415)	(8,010)	24,980
NET INCOME (LOSS)	8,975	16,885	(81,713)
Preferred stock dividends	1,799	4,625	4,625
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ 7,176	$ 12,260	$ (86,338)
EARNINGS (LOSS) PER SHARE—Basic	$ 0.65	$ 0.94	$ (6.07)
EARNINGS (LOSS) PER SHARE—Diluted	$ 0.64	$ 0.93	$ (5.66)
WEIGHTED AVERAGE COMMON SHARES—Basic	11,120,204	13,075,560	14,216,466
WEIGHTED AVERAGE COMMON SHARES—Diluted	11,283,265	13,208,746	15,255,239

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statement of Shareholders' Equity
Year Ended December 31, 2006, 2007, and 2008
(dollars and shares in thousands)

	Preferred shares	Common shares	Preferred par value	Common par value	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income	Total shareholders' equity
BALANCE AT DECEMBER 31, 2005 . . .	—	9,975	$—	$ 10	$ 50,965	$ 10,250	$ —	$ 61,225
Stock Options Exercised	—	103	—	—	556	—	—	556
Warrants Exercised	—	1,164	—	1	13,972	—	—	13,973
Stock Compensation Expense	—	—	—	—	662	—	—	662
Series B Preferred Shares Issued	2,000	—	2	—	47,111	—	—	47,113
Preferred Stock Dividends	—	—	—	—	—	(1,799)	—	(1,799)
Net Income	—	—	—	—	—	8,975	—	8,975
Other Comprehensive Income	—	—	—	—	—	—	776	776
BALANCE AT DECEMBER 31, 2006 . . .	2,000	11,242	$ 2	$ 11	$113,266	$ 17,426	$ 776	$131,481
Stock Options Exercised	—	26	—	—	77	—	—	77
Stock Compensation Expense	—	—	—	—	1,573	—	—	1,573
Preferred Stock Dividends	—	—	—	—	—	(4,625)	—	(4,625)
Shares Issued	—	2,000	—	2	65,627	—	—	65,629
Net Income	—	—	—	—	—	16,885	—	16,885
Other Comprehensive Loss	—	—	—	—	—	—	(2,094)	(2,094)
BALANCE AT DECEMBER 31, 2007 . . .	2,000	13,268	$ 2	$ 13	$180,543	$ 29,686	$(1,318)	$208,926
Stock Options Exercised	—	87	—	—	979	—	—	979
Stock Compensation Expense	—	—	—	—	3,545	—	—	3,545
Preferred Stock Dividends	—	—	—	—	—	(4,625)	—	(4,625)
Shares Issued	—	5,440	—	6	133,685	—	—	133,691
Net Loss	—	—	—	—	—	(81,713)	—	(81,713)
Other Comprehensive Income	—	—	—	—	—		16,614	16,614
BALANCE AT DECEMBER 31, 2008 . . .	2,000	18,795	$ 2	$ 19	$318,752	$(56,652)	$15,296	$277,417

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income
(dollars in thousands)

	Years Ended December 31,		
	2006	2007	2008
Net income (loss)	$8,975	$16,885	$(81,713)
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $718, ($53) and ($7,021), respectively	1,396	(98)	13,629
Reclassification of (gain) loss on settled contracts, net of income taxes of ($319), ($1,027) and $2,060, respectively	(620)	(1,996)	3,999
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $—, $—, and ($522), respectively	—	—	(1,014)
Comprehensive income (loss)	$9,751	$14,791	$(65,099)

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(dollars in thousands)

	Year Ended December 31,		
	2006	2007	2008
CASH FLOWS DUE TO OPERATING ACTIVITIES			
Net income (loss)	$ 8,975	$ 16,885	$ (81,713)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	8,046	18,681	31,744
Impairment of oil and natural gas properties	—	—	151,629
Deferred income taxes	3,415	7,977	(25,006)
Non-cash stock compensation expense	662	1,573	3,085
Other	30	273	521
Decrease (increase) in:			
Accounts receivable	(1,567)	(5,333)	717
Prepaid expenses and other assets	(1,462)	(913)	(1,089)
Increase (decrease) in:			
Accounts payable and accrued expenses	19,955	9,985	6,195
Revenue distributions payable	279	3,317	1,728
Net cash provided by operating activities	38,333	52,445	87,811
CASH FLOWS DUE TO INVESTING ACTIVITIES			
Purchase of oil and natural gas properties	(104,412)	(174,509)	(284,400)
Purchase of property and equipment	(26,161)	(20,489)	(38,534)
Net cash used in investing activities	(130,573)	(194,998)	(322,934)
CASH FLOWS DUE TO FINANCING ACTIVITIES			
Advance on borrowings	78,862	120,139	190,000
Payments on debt	(43,898)	(66,225)	(204,210)
Proceeds from sale of common stock	14,529	65,706	134,681
Proceeds from sale of Series B preferred stock	47,113	—	—
Issuance of 5.00% Convertible Senior Notes	—	—	125,000
Dividends paid on Series B preferred stock	(1,799)	(4,625)	(4,625)
Proceeds from issuance of Senior Secured Notes	—	30,000	—
Fees paid related to financing activities	—	(1,495)	(4,914)
Net cash provided by financing activities	94,807	143,500	235,932
NET INCREASE IN CASH	2,567	947	809
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,393	4,960	5,907
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 4,960	$ 5,907	$ 6,716
SUPPLEMENTAL CASH FLOW DISCLOSURE CASH PAID DURING THE PERIOD FOR:			
INTEREST	$ 683	$ 3,402	$ 10,343
INCOME TAXES	$ —	$ —	$ 26

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements
December 31, 2006, 2007 and 2008

NOTE A—NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

GMX Resources Inc. and subsidiaries, (collectively, "we", "ours", "us", or the "Company") is primarily engaged in the acquisition, exploration, production and development of properties for the production of natural gas and crude oil in Texas, Louisiana and New Mexico.

A summary of the significant accounting policies applied in the preparation of the accompanying financial statements follows.

BASIS OF PRESENTATION: The accompanying consolidated financial statements include the accounts of GMX Resources Inc. and its wholly owned subsidiaries, Endeavor Pipeline, Inc. and Diamond Blue Drilling Co. Endeavor Pipeline, Inc. owns and operates natural gas gathering facilities in East Texas. Diamond Blue Drilling Co. owns drilling rigs and drills natural gas and crude oil wells exclusively for GMX. All significant intercompany accounts and transactions have been eliminated.

USE OF ESTIMATES: The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include estimates for proved oil and natural gas reserve quantities, deferred income taxes, asset retirement obligations, fair value of derivative instruments, useful lives of property and equipment, expected volatility and contract term to exercise outstanding stock options, and others, and are subject to change.

RECLASSIFICATION: Certain reclassifications have been made to prior year amounts to conform to current year presentations.

CASH AND CASH EQUIVALENTS: The Company considers all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

CONCENTRATIONS OF CREDIT RISK: Substantially all of the Company's receivables are within the oil and gas industry, primarily from purchasers of natural gas and crude oil and from partners with interests in common properties operated by the Company. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized; however the Company does review these parties for creditworthiness and general financial condition.

The Company has accounts with separate banks in Louisiana and Oklahoma. At December 31, 2007 and 2008, the Company had $9.5 million and $6.2 million, respectively, invested in overnight investment sweep accounts. The difference between the investment amount and the cash and cash equivalents amount on the accompanying consolidated balance sheets represents uncleared disbursements and non-interest bearing checking accounts.

The Company currently uses two separate counterparties for its natural gas and crude oil commodity derivatives. The counterparties to the Company's derivative instruments are all highly-rated entities with corporate credit ratings at or exceeding A or Aa as classified by Standard & Poor's and Moody's respectively.

Sales to individual customers constituting 10% or more of total oil and natural gas sales were as follows for each of the years ended December 31:

	2006	2007	2008
Oil			
Various purchasers through PVOG	44%	44%	54%
SemCrude, L.P.	0%	0%	17%
Teppco Crude Oil, LLC	48%	55%	14%
Sunoco, Inc.	0%	0%	14%
Natural Gas			
Various purchasers through PVOG	48%	45%	42%
CrossTex Energy Services, Inc.	42%	40%	22%
Texla Energy Management, Inc.	0%	11%	20%
Waskom Gas Processing Company	0%	0%	10%

If the Company were to lose a purchaser, we believe we could replace it with a substitute purchaser with substantially equivalent terms.

INVENTORIES: Inventories consist of crude oil in tanks and natural gas liquids. Treated and stored crude oil inventory and natural gas liquids at the end of the year are valued at the lower of production cost or market.

ACCOUNTS RECEIVABLE: The Company has receivables from joint interest owners and oil and gas purchasers which are generally uncollateralized. The Company generally reviews these parties for creditworthiness and general financial condition. Accounts receivable are generally due within 30 days and accounts outstanding longer than 60 days are considered past due. If necessary, the Company would determine an allowance by considering the length of time past due, previous loss history, future net revenues of the debtor's ownership interest in oil and gas properties operated by the Company and the owners ability to pay its obligation, among other things. The Company writes off accounts receivable when they are determined to be uncollectible.

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. Due to the bankruptcy filing of one purchaser in 2008, the Company has recorded an allowance for doubtful accounts of $748,000 at December 31, 2008. There was no allowance for doubtful accounts at December 31, 2007.

OIL AND NATURAL GAS PROPERTIES: The Company follows the full cost method of accounting for its oil and natural gas properties and activities. Accordingly, the Company capitalizes all costs incurred in connection with the acquisition, exploration and development of oil and natural gas properties. The Company capitalizes internal costs that can be directly identified with exploration and development activities, but does not include any costs related to production, general corporate overhead, or similar activities. Capitalized costs include geological and geophysical work, 3D seismic, delay rentals, drilling and completing and equipping oil and gas wells, including salaries and benefits and other internal costs directly attributable to these activities. Also included in oil and natural gas properties are tubular and other lease and well equipment inventories of $1.5 million and $41.3 million at December 31, 2007 and 2008, respectively, that have not been placed in service but for which we plan to utilize in our on-going exploration and development activities. These inventories are carried at the lower of cost or market, cost being determined by the first-in, first-out method.

Proceeds from dispositions of oil and gas properties are accounted for as a reduction of capitalized costs, with no gain or loss generally recognized upon disposal of oil and natural gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves. Revenues from services provided to working interest owners of properties in which GMX also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties.

Investments in unevaluated properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. The balance of unevaluated properties is comprised of capital costs incurred for undeveloped acreage, exploratory wells in progress and capitalized interest costs. We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full-cost pool and are then subject to amortization.

Depreciation, depletion and amortization of oil and gas properties ("DD&A") are provided using the units-of-production method based on estimates of proved oil and gas reserves and production, which are converted to a common unit of measure based upon their relative energy content. The Company's cost basis for depletion includes estimated future development costs to be incurred on proved undeveloped properties. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs and the anticipated proceeds from salvaging equipment. DD&A expense for oil and natural gas properties was $6.9 million, $16.4 million and $26.9 million for the years ended December 31, 2006, 2007, and 2008, respectively.

Capitalized costs are subject to a "ceiling test," which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10-percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair value of unproved properties.

PROPERTY AND EQUIPMENT: Property and equipment are capitalized and stated at cost, while maintenance and repairs are expensed currently. Depreciation and amortization of other property and equipment are provided using the straight-line method based on estimated useful lives ranging from five to 20 years. Depreciation and amortization expense for property and equipment was $1.2 million, $2.3 million and $4.8 million for the years ending December 31, 2006, 2007, and 2008, respectively.

IMPAIRMENT OF LONG-LIVED ASSETS: Pipeline and gathering system assets and other long-lived assets used in operations are periodically assessed to determine if circumstances indicate that the carrying amount of an asset may not be recoverable in accordance with Statement of Financial Accounting Standard ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long Lived Assets.* This statement requires (a) recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and (b) measurement of an impairment loss as the difference between the carrying amount and fair value of the asset.

DEBT ISSUE COSTS: The Company amortizes debt issue costs related to its revolving bank credit facility, Series A Senior Subordinated Secured Notes, and 5.00% Convertible Senior Notes as interest expense over the scheduled maturity period of the debt. Unamortized debt issue costs were approximately $1.3 million and $4.9 million as of December 31, 2007 and 2008, respectively. The Company includes those unamortized costs in current prepaid expenses and deposits and other assets.

REVENUE DISTRIBUTIONS PAYABLE: For certain oil and natural gas properties, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds applicable to other revenue and royalty owners are reflected as revenue distributions payable in the accompanying balance sheets. We accrue revenue for only our net interest in oil and natural gas properties.

DEFERRED INCOME TAXES: Deferred income taxes are provided for significant carryforwards and temporary differences between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable or deductible amounts in future years. Deferred income tax assets or liabilities are determined by applying the presently enacted tax rates and laws. The Company records a valuation allowance for the amount of net deferred tax assets when, in management's opinion, it is more likely than not that such assets will not be realized.

REVENUE RECOGNITION: Natural gas and crude oil revenues are recognized when 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. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, the Company makes accruals for revenues and accounts receivable based on estimates of its share of production, particularly from properties that are operated by others. Since the settlement process may take 30 to 60 days following the month of actual production, the Company's financial results include estimates of production and revenues for the related time period. The Company records any differences, which are not expected to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

NATURAL GAS BALANCING: During the course of normal operations, the Company and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, cash settlements are made among the joint interest owners under a variety of arrangements. The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. There are no significant imbalances as of December 31, 2007 or 2008.

DERIVATIVE FINANCIAL INSTRUMENTS: The Company may enter into oil and natural gas price swaps and options to manage its exposure to lower oil and natural gas prices. The Company accounts for these transactions in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended ("SFAS 133"). SFAS 133 requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. Upon entering into a derivative contract, we may designate the derivative as either a cash flow hedge or decide that the contract is not a hedge. We document the relationship between the derivative instrument designated as a hedge and the hedged items, as well as our objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as cash flow hedges are linked to specific forecasted transactions. We assess at inception, and on an ongoing basis, whether a derivative instrument used as a hedge is highly effective in offsetting changes in the cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting.

Changes in fair value of a qualifying cash flow hedge are recorded in accumulated other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the statement of operations, the fair value of the associated cash flow hedge is reclassified from accumulated other comprehensive income into earnings as a component of oil and gas sales. Ineffective portions of a cash flow hedge are recognized currently in earnings as a component of oil and gas sales. The changes in fair value of derivative instruments not qualifying or not designated as hedges are reported currently in the consolidated statement of operations as unrealized gains (losses) on derivatives, a component of non-operating income (expense). If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in accumulated other comprehensive income is recognized over the period anticipated in the original hedge transaction.

ASSET RETIREMENT OBLIGATIONS: The Company accounts for asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires entities to 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 oil and gas properties. The Company's asset retirement obligations relate to estimated future plugging and abandonment expenses on its oil and gas properties and related facilities disposal. These obligations to abandon and restore properties are based upon estimated future costs which may change based upon future inflation rates and changes in statutory remediation rules.

ENVIRONMENTAL LIABILITIES: Environmental expenditures that relate to an existing condition caused by past operation and that do not contribute to current or future revenue generation are expensed. Liabilities are accrued when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. As of December 31, 2007 and 2008, the Company has not accrued for or been fined or cited for any environmental violations which would have a material adverse effect upon the financial position, operating results or the cash flows of the Company.

BASIC EARNINGS PER SHARE AND DILUTED EARNINGS PER SHARE: Basic net income per common share is computed by dividing the net income (loss) applicable to common stock by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from our Convertible Notes and outstanding stock options and non-vested restricted stock awards. The following table reconciles the weighted average shares outstanding used for these computations for the years ending December 31:

	2006	2007	2008
Weighted average shares outstanding—basic	11,120,204	13,075,560	14,216,466
Effective of dilutive securities:			
Convertible Notes	—	—	873,870
Stock options	163,061	133,186	164,903
Weighted average shares outstanding—diluted	11,283,265	13,208,746	15,255,239

The dilutive effect of the Convertible Notes varies based on the Company's stock price and for purposes of computing dilutive shares outstanding is based on the average stock price for the Company for the year ended December 31, 2008 of $42.06. The number of shares issuable increases as the Company's common stock price increases and is finally determined based on the Company's volume weighted average stock price for a specified 60 day measurement period ending on or about the actual conversion date.

Common shares loaned in connection with the Convertible Notes in the amount of 3,440,000 shares were not included in the computation of earnings per common share for the year ending December 31, 2008. While the borrowed shares are considered issued and outstanding for corporate law purposes, the Company believes that the borrowed shares are not considered outstanding for the purposes of computing and reporting earnings per share under GAAP currently in effect because the shares lent pursuant to the share lending agreement are required to be returned to the Company.

For the year ending December 31, 2008, the weighted average common shares—basic excludes 62,728 shares of non-vested restricted stock that is subject to future vesting over time. For purposes of calculating weighted average common shares—diluted, the non-vested restricted stock would be included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity. The non-vested shares at December 31, 2008, were excluded from the weighted average common shares—diluted computation as the shares were anti-dilutive. The dilution impact of these shares on our earnings per share calculation may increase in future periods, depending on the market price of our common stock during those periods.

Stock options to acquire approximately 25,000 and 343,000 shares of common stock were outstanding but excluded from the diluted net income per common share calculations for the year ended December 31, 2006 and 2007, respectively, as their exercise prices exceeded the average market price of our common stock during the respective periods; therefore, their inclusion would be anti-dilutive to the calculations.

STOCK BASED COMPENSATION: At December 31, 2008, the Company had stock-based compensation plans that included restricted stock and stock options issued to employees, contractors and non-employee directors as more fully described in Note I—Stock Compensation Plans. The Company accounts for stock-based compensation plans in accordance with SFAS No. 123(R), *Share-Based Payments* ("SFAS No. 123(R)") which requires equity-classified share-based payments to be valued at fair value on the date of grant and to be expensed over the applicable vesting period.

Prior to adopting SFAS No. 123(R), we accounted for our employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* ("APB No. 25") and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. Effective January 1, 2006, we adopted SFAS No. 123(R), using the modified prospective transition method which required any previously granted awards not fully vested at January 1, 2006 to be recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required.

COMMITMENTS AND CONTINGENCIES: Liabilities for loss contingencies arising from claims, assessments, litigation, or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

SUPPLEMENTAL DISCLOSURE OF NON-CASH INVESTING AND FINANCING ACTIVITIES: During the years ended December 31, 2006, 2007 and 2008, the Company recorded non-cash additions to oil and gas properties of $890,000, $2.6 million, and $3.6 million respectively.

During the years ended December 31, 2006, 2007 and 2008, the Company recorded a net non-cash asset and related liability of ($50,000), $1.5 million, and $2.4 million respectively, associated with the asset retirement obligation on the acquisition and/or development of oil and gas properties.

Interest of $111,000, $122,000, and $361,000 was capitalized during the years ended December 31, 2006, 2007, and 2008, respectively, related to the unproved properties that were not being currently depreciated, depleted or amortized and on which development activities were not in progress. In addition, the Company capitalized interest of $84,000 during 2006 related to the construction of two drilling rigs.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS: The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by the Company to determine the impact on its financial statements upon adoption. The Company has concluded that the following new accounting standards are applicable to the Company.

We adopted SFAS No. 157, *Fair Value Measurements,* ("SFAS 157") on January 1, 2008, the first day of fiscal year 2008. SFAS 157 defines fair value, establishes a methodology for measuring fair value, and expands the required disclosure for fair value measurements. On February 12, 2008, the FASB issued FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which amends SFAS 157 by delaying its effective date by one year for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis. On February 14, 2008, the FASB issued FASB Staff Position No. FAS 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*, which amends SFAS 157 to exclude FASB Statement No. 13, *Accounting for Leases*, ("SFAS 13") and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. However, this scope exception does not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under FASB Statement No. 141, *Business Combinations*, ("SFAS 141") or FASB Statement No. 141(R), *Business Combinations*, ("SFAS 141(R)") regardless of whether those assets and liabilities are related to leases. Therefore, beginning on January 1, 2008, SFAS 157 applies prospectively to our new fair value measurements of financial instruments and recurring fair value measurements of non-financial assets and non-financial liabilities that are not specifically excluded. On January 1, 2009, the standard will also apply to all other fair value measurements. See Note D, "Fair Value Measurements," for additional information.

We adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities-Including an Amendment of FASB Statement No. 115,* ("SFAS 159") on January 1, 2008. This standard permits entities to choose to measure many financial instruments and certain other items at fair value. While SFAS 159 became effective for our 2008 fiscal year, we did not elect the fair value measurement option for any of our financial assets or liabilities.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133* ("SFAS No. 161"), which requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The statement requires fair value disclosures of derivative instruments and their gains and losses to be in tabular format, the potential effect on the entity's liquidity from the credit-risk-related contingent features to be disclosed, and cross-referencing within the footnotes. SFAS No. 161 is effective for the Company beginning January 1, 2009. The adoption of this pronouncement will not have an impact on the Company's consolidated financial statements, but it will require the Company to expand its disclosures about derivative instruments.

On December 31, 2008, the Securities and Exchange Commission ("SEC") published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, and permitting disclosure of probable and possible reserves. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The Company is currently assessing the impact that the adoption will have on the Company's disclosures, operating results, financial position, and cash flows.

In May 2008, the FASB issued FASB Staff Position No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion* (Including Partial Cash Settlement) ("FSP APB 14-1"). FSP APB 14-1 requires the issuer of certain convertible debt instruments that may be settled fully or partially in cash upon conversion to separately account for the liability and equity components of the instrument at inception in a manner that reflects the issuer's nonconvertible debt borrowing rate when interest expense is recognized in subsequent periods. FSP APB 14-1 is effective for fiscal years beginning after December 15, 2008 on a retrospective basis and will be adopted by the Company in the first quarter of 2009.

FSP APB 14-1 will affect the accounting treatment of the Company's Convertible Notes which may be fully or partially settled in cash upon conversion. Under the FSP APB 14-1, the initial carrying value of the liability component of our Convertible Notes should approximate the fair value of a similar liability, excluding the conversion feature and any non-substantive embedded features. Utilizing an income approach and based on available market information at the time of issuance, the Company estimates that initial carrying value of the liability component of our Convertible Notes will be approximately $14.3 million less under the FSP APB 14-1 than the amount we recorded at issuance, with a corresponding before-tax increase in additional paid-in capital, reflecting an increase in the effective interest rate on our Convertible Notes of approximately 2.8%, from 5.9% to 8.7%. This adjustment will be recognized during the first quarter of 2009 as a cumulative effect from a change in accounting principle and will reduce beginning retained earnings by approximately $1.2 million after tax. The new higher yield on our Convertible Notes will result in additional interest expense of approximately $7.9 million through the first quarter of 2013.

NOTE B—PROPERTY AND EQUIPMENT

Major classes of property and equipment included the following at December 31:

	2006	2007	2008
		(in thousands)	
Pipeline and related facilities	$16,049	$28,816	$ 50,425
Drilling rigs	23,950	29,924	30,458
Machinery and equipment	1,198	2,047	12,919
Buildings and leasehold improvement	1,254	1,606	4,807
Office equipment	646	958	1,495
	43,097	63,351	100,104
Less accumulated depreciation and amortization	(3,742)	(8,570)	(16,484)
	39,355	54,781	83,620
Land	—	176	1,664
	$39,355	$54,957	$ 85,284

NOTE C—DERIVATIVE ACTIVITIES

The Company is subject to price fluctuations of natural gas and crude oil. Prices received for natural gas and crude oil sold on the spot market are volatile due to factors beyond the Company's control. Reductions in crude oil and natural gas prices could have a material adverse effect on the Company's financial position, results of operations, capital expenditures and quantities of reserves recoverable on an economic basis. Any reduction in reserves, including reductions due to lower prices, can reduce the borrowing base under the Company's revolving bank credit facility and adversely affect the Company's liquidity and ability to obtain capital for acquisition and development activities.

To mitigate a portion of our exposure to fluctuations in commodity prices, the Company enters into financial price risk management activities with respect to a portion of our projected oil and natural gas production through financial price swaps and options. The Company's revolving bank credit facility requires the Company to maintain a hedging program on mutually acceptable terms whenever the loan amount outstanding exceeds 75% of the borrowing base. In addition, the note agreement for the Secured Notes requires the Company to hedge a certain portion of production.

For swap instruments, we received a fixed price and pay a variable price to the contract counterparty. The fixed-price payment and the floating price payment are netted, resulting in a net amount due to or from the counterparty. Options contain a fixed floor price (long put option) and ceiling price (short call option). If the market price exceeds the ceiling price, we pay the difference between the market price and the ceiling price. If the market price is less than the fixed floor price, we receive the difference between the fixed floor price and the market price. If the market price is between the ceiling and the fixed floor price, no payments are due from either party.

The following is a summary of the fair value of our natural gas and crude oil swaps and options at December 31:

	2007	2008
	(in thousands)	
Fair value of derivative asset—current	$ —	$21,325
Fair value of derivative asset—long term	—	3,751
Fair value of derivative liability—current	(1,720)	—
Fair value of derivative liability—long term	(277)	—
	$(1,997)	$25,076

Fair value is generally determined based on the difference between the fixed contract price and the underlying estimated market price at the determination date. Following is a summary of the outstanding volumes and prices on the oil and natural gas swaps and options we have in place as of December 31, 2008:

Effective Date	Maturity Date	Average Notional Amount Per Month	Remaining Notional Amount as of December 31, 2008	Additional Put Option	Floor	Ceiling
Natural Gas (MMBtu):						
6/1/2008	12/31/2009	100,000	1,200,000		$ 9.50	$ 12.20
1/1/2008	12/31/2009	100,000	1,200,000		$ 7.50	$ 8.15
1/1/2009	3/1/2009	189,000	567,000	$5.00	$ 7.50	—
1/1/2009	12/31/2009	189,000	1,696,000		$ 7.50	$ 8.60
1/1/2009	12/31/2009	200,000	2,400,000		$ 7.50	$ 9.17
1/1/2009	12/31/2009	250,000	3,000,000		$ 6.50	— (3)
1/1/2010	12/31/2010	300,000	3,600,000		$ 7.50	$ 8.91
1/1/2010	12/31/2010	172,000	2,062,000	$5.00	$ 7.50	$ 9.05(1)(2)
1/1/2010	12/31/2010	25,000	300,000		—	$ 7.50(3)(4)
1/1/2011	12/31/2011	110,000	1,320,000		—	$ 7.50(3)
Oil (Bbls):						
1/1/2009	12/31/2009	5,000	60,000		$100.00	$134.00

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call (ceiling) establishes the maximum price that we will receive for the contracted commodity volumes. The purchased put (floor) establishes the minimum price that we will receive for the contracted volumes unless the market price for the commodity falls below the sold (lower or additional) put strike price, at which point the minimum price equals the reference price (i.e., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

(2) The sold put has an average notional amount per month of 115,000 MMBtus and is settled at NYMEX.

(3) Derivative transaction is settled at NYMEX. Unless indicated, all other natural gas hedges are settled at Inside FERC—Houston Ship Channel.

(4) Contract was sold in January 2009 and replaced with a contract with an $8.50 ceiling with the same notional amounts and effective and maturity dates.

Natural gas contracts are settled against Inside FERC—Houston Ship Channel Index Price or NYMEX and all oil contracts are settled against NYMEX Light Sweet Crude. The Inside FERC—Houston Ship Channel Index Price and NYMEX Light Sweet Crude have historically had a high degree of correlation with the actual prices received by the Company.

For derivative transactions that qualify for hedge accounting, gains or losses are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as unrealized gains (losses). The components of oil and gas sales as are as follows for the years ended December 31:

	2006	2007	2008
		(in thousands)	
Oil and gas sales	$30,933	$15,551	$130,781
Derivative contract settlements	949	1,499	(6,059)
Gains (losses) on ineffectiveness	—	—	1,014
Total oil and gas sales	$31,882	$17,050	$125,736

Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gain (loss) on derivatives, a component of non-operating income (expense). Assuming that the market prices of oil and gas futures as of December 31, 2008 remain unchanged, the Company would expect to transfer a gain of approximately $11.6 million from accumulated other comprehensive income to earnings during the next 12 months. The actual reclassification into earnings will be based on market prices at the contract settlement date.

NOTE D—FAIR VALUE MEASUREMENTS

Fair value 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 (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company generally applies the market and income approaches for recurring fair value measurements and utilizes the best available information. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company has reviewed their recurring transactions and found that their markets and instruments are fairly liquid and has established that they are able to transact at the mid-point of the bid/ask spread. The Company is able to classify fair value balances based on the observability of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities, and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At each balance sheet date, the Company performs an analysis of all instruments subject to SFAS 157 and includes in Level 3 all of those whose fair value is based on significant unobservable inputs. As of December 31, 2008, the Company had no Level 3 measurements.

The carrying values of *Cash and Cash Equivalents, Accounts Receivable-interest owners, Accounts Receivable-oil and natural gas revenues, Accounts Payable, Accrued Expenses, Revenue Distribution Payable,* and *Other Liabilities* included in the accompanying consolidated balance sheets approximated fair value at December 31, 2008. These assets and liabilities are not presented in the following tables.

The following table sets forth by level within the fair value hierarchy the Company's financial assets that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	As of December 31, 2008				
			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs	Significant Unobservable Inputs (Level 3)
			(in thousands)		
Financial assets:					
Natural gas swaps and options	$ 22,224	$ 22,224	$ —	$22,224	$ —
Crude oil swaps and options	$ 2,852	$ 2,852	$ —	$ 2,852	$ —
Financial liabilities:					
Long-term debt	$236,523	$233,225	$196,433	$36,792	$ —

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above. As per the requirements under SFAS 157, all fair values reflected in the table above and on the balance sheet have been adjusted for non-performance risk. The adjustment to fair value related to non-performance risk as of December 31, 2008, was a reduction of the net asset value of approximately $247,000.

Level 1 Fair Value Measurements

Long Term Debt—The fair value of our revolving bank credit facility and our joint venture financing is the carrying value. The Convertible Notes are actively traded in an established market. The fair values of this debt is based on quotes obtained from brokers.

Level 2 Fair Value Measurements

Forward Natural Gas Swaps and Options—The fair value of the forward natural gas swaps and options are estimated using a combined income and market based valuation methodology based upon forward commodity price curves. The curves are obtained from independent pricing services reflecting broker market quotes.

Forward Crude Swaps and Options—The fair value of the forward crude swaps and options are estimated using a combined income and market based valuation methodology based upon forward commodity price curves. The curves are obtained from independent pricing services reflecting broker market quotes.

Long Term Debt—The Secured Notes do not actively trade in an established market. The fair values of this debt are estimated by discounting the principal and interest payments at rates available for debt with similar terms and maturity.

Level 3 Fair Value Measurements

As of December 31, 2008, the Company did not have assets or liabilities measured under a Level 3 fair value hierarchy.

NOTE E—LONG-TERM DEBT

Long-term debt consists of the following at December 31:

	2007	2008
	(in thousands)	
Revolving bank credit facility, maturity date of July 2011 bearing a weighted average interest rate of 6.88% and 3.25% as of December 31, 2007 and 2008, respectively, collateralized by all assets of the Company	$ 89,860	$ 80,000
Bridge Loan, maturity date of June 2008, bearing interest at prime rate plus 2.25% (effective rate of 9.5% at December 31, 2007)	4,140	—
5.00% Convertible Senior Notes due February 2013	—	125,000
Senior Subordinated Secured Notes due July 2012 with a fixed interest rate of 7.58% and secured by a second lien on all assets of the Company	30,000	30,000
Joint venture financing (non-recourse, no interest rate)	1,734	1,523
	125,734	236,523
Less current maturities	4,321	61
	$121,413	$236,462

Maturities of long-term debt as of December 31, 2008 are as follows:

Year	Amount (in thousands)
2009	$ 61
2010	55
2011	80,050
2012	30,046
Thereafter	126,250
	$236,462

Revolving Bank Credit Facility

The Company has an executed loan agreement providing for a secured revolving line of credit up to an amount established as the borrowing base which is based on the Company's oil and natural gas reserves (the "borrowing base"). The loan bears interest at the rate elected by the Company of either the prime rate as published in the Wall Street Journal (payable monthly) or the LIBO rate plus a margin ranging from 1.75% to 2.25% based on the amount of the loan outstanding in relation to the borrowing base for a period of one, two or three months (payable at the end of such period). Principal is payable voluntarily by the Company or is required to be paid (i) if the loan amount exceeds the borrowing base; (ii) if the Lender elects to require periodic payments as a part of a borrowing base re-determination; and (ii) at the maturity date of July 15, 2011. The Company is obligated to pay a facility fee equal to 0.25% per year of the unused portion of the borrowing base payable quarterly. The borrowing base has been adjusted from time to time and was $190 million at December 31, 2008. The loan is secured by a first mortgage on assets of the Company. The loan agreement was also amended in February 2008 to permit the sale of 5.00% Convertible Senior Notes due 2013. Also as part of the regular redetermination in 2008, the Company and the banks executed an amended and restated loan agreement providing for up to $250 million in loans as the borrowing base permits. The revolving bank credit facility was repaid in July 2008 with proceeds from a common stock offering. The Company has subsequently reborrowed on the facility to fund development and exploration activities and for general corporate purposes.

In December 2007, the Company entered into an agreement to grant a temporary increase in the borrowing base of $30 million (the "Bridge Loan") from the existing $90 million to $120 million until the earlier of the completion of additional financing or June 30, 2008. The Bridge Loan bore interest at a rate that is 2.25% higher per annum than our other borrowings under the normal borrowing base and the unused facility fee is 0.25% higher than the 0.25% fee for the normal borrowing base. In connection with the amendment, the Company paid an upfront commitment and arrangement fees of 2.5% of the Bridge Loan of $750,000. Upon closing of the issuance of our $125 million 5.00% Convertible Senior Notes in February 2008, we repaid the Bridge Loan.

The agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, and changes in management and require the maintenance of various financial ratios. The required and actual financials ratios as of December 31, 2008 are shown below:

Financial Covenant	Required Ratio	Actual Ratio
Current ratio[(1)]	Not less than 1 to 1	2.25 to 1
Maintain a minimum net worth[(2)]	$355.1 million	$362.2 million
Ratio of EBITDA, as defined in the revolving bank credit facility agreement to cash interest expense[(3)]	Not less than 3 to 1	6.07 to 1

(1) Current ratio is defined in our revolving bank credit facility as the ratio of current assets plus the unused and available portion of the revolving bank credit facility ($110 million as of December 31, 2008) to current liabilities. The calculation will not include the effects, if any, of derivatives under SFAS No. 133. As of December 31, 2008, current assets included derivatives assets of $21.3 million. In addition, the convertible notes are not considered a current liability unless one or more convertible notes have been surrendered for conversion and then only to the extent of the cash payment due on the conversion of the notes surrendered. As of December 31, 2008, none of the convertible notes had been surrendered for conversion.

(2) The minimum net worth requirement is adjusted quarterly with the amount to be met being increased (but not reduced) by the sum of 50% of the Company's positive net income in each quarter plus 100% of the net proceeds from stock or other equity offerings. The non-cash effects, if any, of derivative instruments pursuant to SFAS No. 133 are not included, as well as ceiling test write-downs pursuant to regulation S-X 4-10 of the Securities and Exchange Commission.

(3) EBITDA as defined in our revolving bank credit facility as of December 31, 2008 is calculated as follows (amounts in thousands):

Net loss	$(81,713)
Plus:	
Interest expense	11,681
Impairment of oil and natural gas properties	151,629
Depreciation, depletion and amortization	31,744
Other non-cash expenses	3,606
Less:	
Income tax benefit	24,980
EBITDA	$ 91,967

Cash interest expense is defined in the revolving bank credit facility as all interest, fees, charges, and related expenses payable in cash for the applicable period payable to a lender in connection with borrowed money or the deferred purchase price of assets that is considered interest expense under GAAP, plus the portion of rent paid or payable for that period under capital lease obligations that should be treated as interest in accordance with SFAS No. 13, *Accounting for Leases*. For 2008, cash interest expense included fees paid related to financing activities and other loan fees of $5.1 million. As of December 31, 2008, non-cash interest expense of $1.7 million was deducted from interest expense to arrive at the cash interest expense used in the debt covenant calculation. Non-cash interest expense primarily relates to the amortization of debt issuance costs.

As of December 31, 2008, the Company was in compliance with financial covenants under the revolving bank credit facility, except for the minimum net worth financial covenant for which the bank credit facility was amended effective December 31, 2008 to amend the minimum net worth calculation to exclude the non-cash effects of ceiling test write-downs pursuant to Regulation S-X Rule 4-10 of the Securities and Exchange Commission.

Our lenders may accelerate all of the indebtedness under our revolving bank credit facility upon the occurrence of any event of default unless we cure any such default within any applicable grace period. For payments of principal and interest under the revolving bank credit facility, we generally have a three business day grace period, and we have a 30-day cure period for most covenant defaults, but not for defaults of certain specific covenants, including our financial covenants and negative covenants.

5.00% Convertible Senior Notes

In February 2008, we completed a $125 million private placement of 5.00% Convertible Senior Notes due 2013 ("Convertible Notes"). In connection with such offering, we agreed to loan up to 3,846,150 shares of our common stock to an affiliate of Jefferies & Company, Inc. to facilitate hedging transactions by purchasers of the notes. The Bridge Loan and revolving bank credit facility were paid in full with the net proceeds of $121 million of the Convertible Notes.

The Convertible Notes bear interest at a rate of 5.00% per year, payable semiannually in arrears on February 1 and August 1 of each year, beginning August 1, 2008. The Convertible Notes mature on February 1, 2013, unless earlier converted or repurchased by us.

Holders may convert their Convertible Notes at their option prior to the close of business on the business day immediately preceding November 1, 2012 only under the following circumstances:

- during any fiscal quarter commencing after March 31, 2008 if the last reported sale price of the common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter is greater than or equal to 130% of the applicable conversion price on each such trading day;
- during the five business-day period after any five consecutive trading-day period in which the trading price for each day of that measurement period was less than 98% of the last reported sale price of our common stock and the applicable conversion rate on each such day; or
- the occurrence of certain sales of assets, distributions or changes to distribution rights to common stockholders, mergers and consolidations, changes in management, or our common stock ceases to be listed on a United States national or regional securities exchange, among other things.

On and after November 1, 2012 until the close of business on the business day immediately preceding the maturity date, holders may convert their Convertible Notes at any time, regardless of the foregoing circumstances.

Upon conversion, we will satisfy our conversion obligation by paying and delivering cash for the lesser of the principal amount or the conversion value, and, if the conversion value is in excess of the principal amount, by paying or delivering, at our option, cash and/or shares of our common stock for such excess. The conversion value is a daily value calculated on a proportionate basis for each day of a 60 trading-day observation period. The conversion rate is initially 30.7692 shares of the Company's common stock per $1,000 principal amount of notes (equivalent to a conversion price of approximately $32.50 per share of common stock). The conversion rate is subject to adjustment in some events but will not be adjusted for accrued interest. In addition, following any fundamental change that occurs prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its Convertible Notes in connection with such a fundamental change in certain circumstances. The increase in the conversion rate is determined based on a formula that takes into consideration our stock price at the time of the fundamental change (ranging from $25.00 to $150.00 per share) and the remaining time to maturity of the notes. The increase in the conversion rate ranges from 0% to 30% increasing as the stock price at the time of the fundamental change increases from $25.00 and declines as the remaining time to maturity of the notes decreases.

We may not redeem the Convertible Notes prior to maturity. However, if we undergo a fundamental change, holders may require us to repurchase the Convertible Notes in whole or in part for cash at a price equal to 100% of the principal amount of the Convertible Notes to be repurchased plus any accrued and unpaid interest (including additional interest, if any) to, but excluding, the fundamental change repurchase date.

The Convertible Notes are senior unsecured obligations of the Company and rank equally in right of payment to all of the Company's other existing and future senior indebtedness. The Convertible Notes are effectively subordinated to all our secured indebtedness, including indebtedness under our revolving bank credit facility and our Secured Notes, to the extent of the value of our assets pledged as collateral for such indebtedness. The Convertible Notes are also effectively subordinated to all liabilities of our subsidiaries, including liabilities under any guarantees they have issued.

Senior Subordinated Secured Notes

In July 2007, we entered into a Note Purchase Agreement ("Note Agreement") with The Prudential Insurance Company of America ("Prudential") providing for the issuance and sale from time to time of up to $100 million in senior subordinated secured notes (the "Secured Notes") and sold to Prudential an initial tranche of $30 million of 7.58% Series A fixed rate notes due July 31, 2012 with interest payable quarterly. Proceeds from the sale of the Secured Notes were used for general corporate purposes including additional funding of drilling and development costs in the Cotton Valley Sands in East Texas. The Secured Notes are secured by a second lien on all of the assets of the Company and its subsidiaries and are guaranteed by the Company's subsidiaries, subject to the terms of an Intercreditor Agreement between our senior lenders and the collateral agent for the Noteholders, including Prudential. We amended the Note Agreement in February 2008 in connection with the sale of the 5.00% Convertible Senior Notes due 2013. In the event of a change in control, defined to be an acquisition of greater than 50% of our outstanding voting stock (other than an acquisition by a public company meeting specified financial requirements) or change in management (defined as Ken L. Kenworthy, Jr. not being the chief executive officer for any reason, except that upon Mr. Kenworthy's death or disability, we have the ability to avoid a change in management if we name a successor chief executive officer acceptable to Prudential within four months), we are required to give notice to the Noteholders and offer to repurchase the Secured Notes at the outstanding principal amount plus accrued interest plus, in the case of any fixed rate notes, including the Secured Notes, a yield maintenance amount.

The Note Agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, and changes in management and require the maintenance of various financial ratios. The required and actual financial ratios as of December 31, 2008 are below:

Financial Covenant	Required Ratio	Actual Ratio
Maintain a ratio of Adjusted PV10 to total debt(1)	Not less than 1.5 to 1	1.75 to 1
Maintain a minimum tangible net worth(2)	$289.5 million	$262.1 million
Ratio of total debt to EBITDA(3)	Not greater than 4 to 1	2.57 to 1
Ratio of EBITDA to interest expense including dividends on outstanding preferred stock(3)(4)	Not less than 2.5 to 1	5.52 to 1

(1) Adjusted PV10 as calculated under the Note Agreement was $413.0 million as of December 31, 2008.

(2) The minimum tangible net worth requirement is adjusted quarterly with the amount to be met being increased (but not reduced) by the sum of 50% of the Company's positive net income in each quarter plus 100% of the net proceeds from stock or other equity offerings. The non-cash effects, if any, of derivative instruments pursuant to SFAS No. 133 and ceiling test write-downs are not included.

(3) EBITDA is calculated in the same manner required under our revolving bank credit facility.

(4) Interest expense as defined in the Note Agreement is equal to our interest expense reflected in our consolidated statements of operations plus capitalized interest of $361,000 and preferred stock dividends of $4.6 million.

As of December 31, 2008, the Company was in compliance or has received a waiver with the financial covenants under the Note Agreement. As of December 31, 2008, due to the impairment charge of $151.6 million to oil and gas properties, the Company did not meet the minimum tangible net worth covenant. Prudential agreed to waive compliance with this covenant at December 31, 2008 and amend the minimum consolidated tangible net worth to be not less than $165 million plus the sum of (i) 50% of positive net income in each fiscal quarter commencing with the quarter ending March 31, 2008, and (ii) 100% of the net cash proceeds from the issuance and sale of stock or other equity offering after December 31, 2008.

The holders of our Secured Notes may declare the Secured Notes immediately due and payable upon the occurrence of any event of default under the Note Agreement unless we cure any such default within any applicable grace period. For payments of interest (but not principal and other required amounts) on the Secured Notes, we generally have a three-day grace period from the due date.

Joint Venture Financing

In 2004, we entered into an arrangement with Penn Virginia Oil & Gas, L.P. ("PVOG") to purchase dollar denominated production payments from the Company on certain wells drilled during a portion of 2004. Under this agreement, PVOG provided $2.8 million in funding for our share of costs of four wells drilled which is repayable solely from 75% of GMX's share of production revenues from these wells without interest.

NOTE F—ASSET RETIREMENT OBLIGATIONS

The activity incurred in the asset retirement obligation is as follows:

	2007	2008
	(in thousands)	
Beginning balance	$2,163	$3,625
Liabilities incurred	1,188	2,742
Liabilities settled	—	(256)
Accretion	178	273
Revisions	96	(335)
Ending balance[1]	3,625	6,049
Less current portion[1]	525	587
	$3,100	$5,462

[1] The Company's liability for asset retirement obligations is included in other liabilities in the consolidated balance sheets, net of the current obligations. The current portion is included in accrued expenses in the consolidated balance sheets.

NOTE G—INCOME TAXES

Income tax expense consists of the following for the years ended December 31:

	2006	2007	2008
		(in thousands)	
Current tax expense	$ —	$ 33	$ 26
Deferred tax expense	3,415	7,977	(25,006)
	$3,415	$8,010	$(24,980)

Total income tax expense differed from the amounts computed by applying the U.S. federal tax rate to earnings before income taxes as a result of the following for the years ended December 31:

	2006	2007	2008
U.S. statutory tax rate	34%	34%	34%
Statutory depletion	(4)	(4)	(4)
Change in valuation allowance	—	—	(11)
Other	(2)	2	4
Effective income tax rate	28%	32%	23%

Intangible development costs may be capitalized or expensed for income tax reporting purposes, whereas they are capitalized and amortized for financial statement purposes. Lease and well equipment and other property and equipment may be depreciated for income tax reporting purposes using accelerated methods and different lives.

Other temporary differences include the effect of hedging transactions and stock based compensation awards. Deferred income taxes are provided on these temporary differences to the extent that income taxes which otherwise would have been payable are reduced. Deferred income tax assets are also available to offset future income taxes.

The following table sets forth the Company's deferred tax assets and liabilities at December 31:

	2006	2007	2008
		(in thousands)	
Deferred tax assets:			
Federal net operating loss carryforwards	$ 9,455	$ 10,318	$ 11,473
Statutory depletion carryforwards	2,722	3,627	3,588
Stock option compensation expense	120	311	641
Derivative instruments	—	680	734
Oil and natural gas properties	—	—	10,187
Other	—	243	450
Less: Valuation allowance on deferred tax assets not expected to be realized	—	—	(11,473)
Total	12,297	15,179	15,600
Deferred tax liabilities:			
Oil and natural gas properties	(16,649)	(25,805)	—
Property and equipment	(275)	(1,299)	(1,817)
Derivative instruments	(400)	—	(9,260)
Total	(17,324)	(27,104)	(11,077)
Net deferred tax asset (liability)	$ (5,027)	$(11,925)	$ 4,523

At December 31, 2008, the Company had federal net operating loss carryforwards of $33.7 million which will begin to expire in 2018 if unused. The Company's federal net operating loss carryforward has an annual limitation under Internal Revenue Code Section 382. In addition, at December 31, 2008, the Company had tax percentage depletion carryforwards of approximately $10.6 million which are not subject to expiration.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Management is uncertain whether the Company's future taxable income will be sufficient to utilize the federal net operating loss carryforward. This uncertainty is based on the annual limitations in the amount of net operating loss carryforwards available to reduce taxable income, our lack of historical taxable income and our continued projected drilling. Therefore, as of December 31, 2008, we recorded a valuation allowance related to this carryforward. Based upon the level of projections for future taxable income and the reversal of future taxable differences over the period which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of the remaining deductible differences as of December 31, 2008.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before and including 2004.

The Company adopted the provision of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN No. 48"), on January 1, 2007. There was no financial statement adjustment required as a result of adoption. We have not paid any significant interest or penalties associated with our income taxes, but classify both interest expense and penalties as part of our income tax expense.

NOTE H—COMMITMENTS AND CONTINGENCIES

The Company is party to various other legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to the Company and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, the Company's estimates of the outcomes of such matters, and its experience in contesting, litigating, and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to the Company's financial position or results of operations after consideration of recorded accruals.

The Company has entered into operating lease agreements for fractional interest in an aircraft, 4 drilling rigs, office space and equipment. The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2008.

Year	Amount (in thousands)
2009	$ 17,852
2010	43,792
2011	43,731
2012	26,707
Thereafter	294
Total	$132,376

We also entered into a two year contract for a drilling rig for a total potential commitment of $16.1 million. The contract is cancelable for a $2 million penalty.

Rent expense for the years ended December 31, 2006, 2007, and 2008 was $154,000, $239,000, and $693,000 respectively.

NOTE I—STOCK COMPENSATION PLANS

We recognized $662,000, $1.6 million and $3.1 million of stock compensation expense for the years ending December 31, 2006, 2007 and 2008, respectively. These non-cash expenses are reflected as a component of the Company's general and administrative expense. To the extent amortization of compensation costs relates to employees directly involved in exploration and development activities, such amounts are capitalized to oil and natural gas properties. Stock based compensation capitalized as part of oil & natural gas properties was $526,000 for the year ended December 31, 2008.

2008 Long-Term Incentive Plan

In May 2008, the Board of Directors and shareholders adopted the 2008 Long-Term Incentive Plan (or "LTI Plan") to retain and attract employees, consultants and directors, and to stimulate the active interest in the development and financial success of the Company. The LTI Plan provides for the grant of stock options, restricted stock awards, bonus stock awards, stock appreciation rights, performance units and performance bonuses, subject to certain conditions. Subject to certain adjustments, the aggregate number of shares of common stock available for awards may not exceed 750,000 shares, nor shall any individual employee award exceed 200,000 shares or $1,000,000 in any calendar year. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the LTI Plan become vested at dates or upon the satisfaction of certain performance or other criteria as determined by the Board of Directors. No awards may be granted under the LTI Plan after May 2018.

2000 Stock Option Plan

In October 2000, the Board of Directors and shareholders adopted the GMX Resources Inc. Stock Option Plan (the "2000 Option Plan"). Under the 2000 Option Plan, the Company may grant both stock options intended to qualify as incentive stock options under Section 422 of the Internal Revenue Code and options which are not qualified as incentive stock options.

The maximum number of shares of common stock issuable under the 2000 Option Plan, as amended in May 2007, is 850,000, subject to appropriate adjustment in the event of reorganization, stock split, stock dividend, reclassification or other change affecting the Company's common stock. All officers, employees and directors are eligible to receive awards under the 2000 Option Plan. The exercise price of options granted is not less than 100% of the fair market value of the shares on the date of grant. Options granted become exercisable as the Board of Directors may determine in connection with the grant of each option. In addition, the Board of Directors may at any time accelerate the date that any option granted becomes exercisable. Stock options generally vest over four years and have a 10-year contractual term.

The Board of Directors may amend or terminate the 2000 Option Plan at any time, except that no amendment will become effective without the approval of the shareholders except to the extent such approval may be required by applicable law or by the rules of any securities exchange upon which the Company shares are admitted to listed trading. The 2000 Option Plan will terminate in 2010, except with respect to awards then outstanding.

Stock Options

The following table provides information related to stock option activity under the 2000 Option Plan for the years ended December 31, 2006, 2007 and 2008:

	Number of shares underlying options	Weighted average exercise price per share	Aggregate intrinsic value[1]	Weighted average grant date fair value per share
Outstanding as of December 31, 2005	322,750	$ 8.65		
Granted	53,000	35.31		$21.88
Exercised	(102,500)	5.42	$3,250,000	
Forfeited	(3,000)	27.91		
Outstanding as of December 31, 2006	270,250	$14.89		
Granted	336,000	38.14		$14.46
Exercised	(25,750)	3.00	$ 798,000	
Forfeited	(6,000)	31.27		
Outstanding as of December 31, 2007	574,500	$28.86		
Granted	100,000	25.84		$25.84
Exercised	(73,450)	13.34	$2,396,000	
Forfeited	(18,000)	33.41		
Outstanding as of December 31, 2008	583,050	$30.16	$ —	
Exercisable as of December 31, 2008	214,250	$24.09	$3,797,000	

(1) The intrinsic value is the amount by which the market value of the underlying stock exceeds the exercise price.

The weighted-average remaining contractual life of outstanding and exercisable options at December 31, 2008 was 7.9 and 7.0 years, respectively.

The Company received $980,000 in cash for option exercises in 2008. No current tax benefits were realized due to availability of a net operating loss carryforward for tax purposes.

As of December 31, 2008 there was $4,282,000 of total unrecognized compensation costs related to non-vested stock options granted under the Company's stock option plan. That cost is expected to be recognized over a weighted average period of 2.3 years.

The fair value of all options granted have been based on the Black Scholes Option pricing model based on the assumptions of an expected life of four years, an expected dividend yield of 0%, risk free interest rates ranging from 1% to 4.95% depending on the date of grant, and stock price volatility calculated at the date of grant ranging from 39% to 144%.

The Company estimated volatility is based on the historical volatility of the Company's common stock. The risk free interest rate is based on the U. S. Treasury yield curve in effect at the time of grant for the expected term of the option. The expected dividend yield is based on the Company's current dividend yield and the best estimate of projected dividend yield for future periods within the expected life of the option.

Restricted Stock

In July 2008, the Company began issuing restricted stock awards to its officers, independent directors, consultants and certain employees under the LTI Plan. The holders of these shares have all the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain passage of time requirements are met. With respect to the restricted stock granted to officers, consultants, and employees of the Company, the shares vest over a 3 year period. With respect to restricted shares issued to the Company's independent board members, the shares vest over a two year period. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. The value is amortized over the vesting period.

A summary of the status of our unvested shares of restricted stock and the changes during the year ended December 31, 2008 is presented below:

	Number of unvested restricted shares	Weighted average grant-date fair value
Unvested shares at January 1, 2008	—	$ —
Granted	79,347	74.11
Vested	(16,521)	76.65
Forfeited	(98)	76.73
Unvested shares as of December 31, 2008	62,728	$73.44

As of December 31, 2008, there was $4.5 million of unrecognized compensation expense related to non-vested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.4 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the year ended December 31, 2008, we did not recognize excess tax benefits related to the vesting of restricted stock due to the market price of the common stock at the date of grant exceeding the market price at the vesting date.

401(k) Plan

The GMX Resources Inc. 401(k) Plan was adopted April 15, 2001. The plan is a qualified retirement plan under the Internal Revenue Code. All employees are eligible who have attained age 21. GMX matches the employee contributions up to 5% of the employee's gross wages. The Company contributed $87,000, $115,000 and $448,000 in 2006, 2007 and 2008, respectively.

NOTE J—CAPITAL STOCK

The Company's Class A warrants issued in our initial public offering in 2001 allowed holders to purchase 1,250,000 common shares at $12.00 per share and expired in February 2006. In 2006, prior to the expiration of the warrants, we received approximately $14 million in exercise proceeds and issued an additional 1,164,326 shares of common stock.

In February 2007, the Company completed a public offering of 2,000,000 shares of our common stock for $34.82 per share. Net proceeds to the Company were approximately $65.6 million, which the Company used to fund drilling and development of our East Texas properties and for other general corporate purposes and to reduce indebtedness under our revolving bank credit facility.

In July 2008, the Company completed an offering of 2,000,000 shares of common stock for $70.50 per share. Net proceeds to the Company were approximately $134 million. The Company repaid outstanding indebtedness under its revolving bank credit facility. The balance of the net proceeds were used to fund the development of oil and natural gas properties, acquisitions of additional oil and natural gas properties and for general corporate purposes.

In August 2006, GMX sold 2,000,000 shares of 9.25% Series B Cumulative Preferred Stock at $25.00 per share in a public offering, resulting in a total offering of $50 million. The net proceeds of $47.1 million from the sale of preferred stock were used to fund the drilling and development of the Company's East Texas properties and for other general corporate purposes. The annual dividend on each share of Series B Cumulative Preferred Stock is $2.3125 (an aggregate of $4.6 million) and is payable quarterly when, as and if declared by the Company, in cash (subject to specified exceptions), in arrears to holders of record as of the dividend payment record date, on or about the last calendar day of each March, June, September and December.

The Series B Cumulative Preferred Stock is not convertible into the Company's common stock and can be redeemed at the Company's option after September 30, 2011 at $25.00 per share. The Series B Cumulative Preferred Stock will be required to be redeemed prior to September 30, 2011 at specified redemption prices and thereafter at $25.00 per share in the event of a change of ownership or control of the Company if the acquirer is not a public company meeting certain financial criteria.

NOTE K—OIL AND NATURAL GAS OPERATIONS

Costs incurred in oil and natural gas property acquisitions, exploration, and development activities are as follows for the years ended December 31:

	2006	2007	2008
		(in thousands)	
Development and exploration costs:			
Development drilling	$ 99,778	$168,246	$183,081
Exploratory drilling	—	—	15,943
Tubular and other drilling inventories	—	—	39,773
Asset retirement obligation	337	1,463	2,407
	100,115	169,709	241,204
Acquisition:			
Proved	4,542	7,814	23,246
Unproved[1]	598	1,018	26,236
	5,140	8,832	49,482
Total	$105,255	$178,541	$290,686

(1) Includes $111,000, $122,000, and $361,000 of capitalized interest for the years ended December 31, 2006, 2007, and 2008, respectively.

Development costs include the cost of drilling and equipping development wells and constructing related production facilities for extracting, treating, gathering, and storing oil and natural gas from proved reserves.

Costs excluded from amortization are as follows at December 31:

	2007	2008
	(in thousands)	
Unproved property acquisition	$2,142	$21,660
Exploratory drilling	—	14,374
	$2,142	$36,034

Unproved property acquisition costs include costs to acquire new leasehold, unevaluated leaseholds, and capitalized interest. Of the $21.7 million of unproved property costs at December 31, 2008 being excluded from the amortization base, $74,000, $482,000 and $21.0 million were incurred in 2006, 2007, and 2008, respectively and $79,000 was incurred in prior years. Subject to industry conditions, evaluation of most of these properties and the inclusion of their costs in the amortized capital costs, is expected to be completed within three years.

The average DD&A rate per equivalent unit of production was $1.59, $1.88 and $2.08 for the years ended December 31, 2006, 2007 and 2008, respectively.

NOTE L—SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

The oil and natural gas reserve quantity information presented below is unaudited and is based upon reports prepared by independent petroleum engineers. The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise. The Company's reserve estimates were estimated by performance methods, volumetric methods, and comparisons with analogous wells, where applicable. The reserves estimated by the performance method utilized extrapolations of historical production data. Reserves were estimated by the volumetric or analogous methods in cases where the historical production data was insufficient to establish a definitive trend. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

The reserves shown in the table below are net wellhead volumes that have not been reduced for lease use volumes (volumes that are consumed or lost between the wellhead and the point of custody transfer). Lease use volumes were estimated to be 6%, 6%, 10% of ending proved reserves as of December 31, 2006, 2007, and 2008, respectively. Historically, the Company has reduced the base natural gas price used in determining future cash inflows to compensate for lease use volumes and in determining a net realized price.

Proved oil and natural gas reserves represent the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. As of December 31, 2006, 2007 and 2008, all of the Company's oil and natural gas reserves were located in the United States.

	OIL (MBBLS)	GAS (MMCF)
December 31, 2006		
Proved reserves, beginning of period	1,967	149,969
Extensions, discoveries, and other additions	831	87,754
Production	(69)	(3,915)
Revisions of previous estimates	(36)	3,042
Proved reserves, end of period	2,693	236,850
Proved developed reserves:		
Beginning of period	764	41,161
End of period	932	69,279
December 31, 2007		
Proved reserves, beginning of period	2,693	236,850
Extensions, discoveries, and other additions	2,019	185,730
Production	(127)	(7,974)
Revisions of previous estimates	108	(8,264)
Proved reserves, end of period	4,693	406,342
Proved developed reserves:		
Beginning of period	932	69,279
End of period	1,776	144,164
December 31, 2008		
Proved reserves, beginning of period	4,693	406,342
Extensions, discoveries, and other additions	1,613	132,434
Production	(190)	(11,777)
Revisions of previous estimates	(1,112)	(91,678)
Proved reserves, end of period	5,004	435,321
Proved developed reserves:		
Beginning of period	1,776	144,164
End of period	1,920	150,585

The increase in proved reserves from extensions, discoveries, and other additions in each period is the direct result of additional drilling on the Company's acreage in East Texas, specifically the exploitation of the Cotton Valley formation. Over the past several years as the Company has drilled Cotton Valley wells, additional offsets have been proved (using SEC definitions of offset as only within one spacing unit of any existing producer or test). The revisions of previous estimates during 2006 was the result of revised natural gas prices. The revision of previous estimates of natural gas reserves at year end 2007 was related to decreases in proven and changes in timing of drilling undeveloped reserves presuming a 20 acre pattern of development. The revision of previous estimates at year end 2008 is due to significantly lower oil and natural gas prices at year end 2008 compared to year end 2007.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and natural gas to be produced. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax bases of the properties and related carryforwards giving effect to permanent differences. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board, and, as such do not necessarily reflect the Company's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The following summary sets forth the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure prescribed in Statement of Financial Accounting Standards No. 69 as of December 31:

	2006	2007	2008
		(in thousands)	
Future cash inflows	$1,337,671	$ 3,549,360	$ 2,586,574
Future production costs	(508,221)	(1,097,465)	(1,014,500)
Future development costs	(309,907)	(555,623)	(559,777)
Future income tax provisions	(116,610)	(528,126)	(187,084)
Net future cash inflows	402,933	1,368,146	825,213
Less effect of a 10% discount factor	(268,499)	(940,416)	(596,420)
Standardized measure of discounted future net cash flows	$ 134,434	$ 427,730	$ 228,793

Oil and natural gas prices were based on period end base prices, with adjustments to the base price for each lease for quality, contractual agreements, lease use shrinkage and regional price variations. Future income tax expenses are computed by applying the appropriate statutory rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved giving effect to permanent differences, tax credits, and allowances relating to proved oil and natural gas reserves.

GMX Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements—(Continued)
December 31, 2006, 2007 and 2008

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows at December 31:

	2006	2007	2008
		(in thousands)	
Standardized measure, beginning of year	$ 185,520	$ 134,434	$ 427,730
Sales of oil and natural gas, net of production costs	(26,938)	(53,131)	(110,375)
Net changes in prices and production costs	(110,559)	182,156	(255,999)
Change in estimated future development costs	(38,708)	75,335	96,063
Extensions and discoveries, net of future development costs	62,948	172,308	49,551
Previously estimated development cost incurred	104,707	30,977	120,028
Revisions of quantity estimates	13,360	(17,257)	(106,288)
Accretion of discount	22,676	54,192	164,367
Changes in timing of production and other	(91,507)	(25,081)	(269,525)
Net changes in income taxes	12,935	(126,203)	113,241
Standardized measure, end of year	$ 134,434	$ 427,730	$ 228,793

NOTE M—QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for 2007 and 2008 are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in thousands, except per share data)				
2008					
Oil and gas sales	$27,199	$38,040	$36,408	$ 24,089	$ 125,736
Income (loss) before income taxes	9,877	17,984	15,276	(149,830)	(106,693)
Net income (loss)	6,496	12,553	10,284	(111,046)	(81,713)
Net income applicable (loss) to common stock	5,340	11,396	9,128	(112,202)	(86,338)
Basic earnings (loss) per share(1)	0.40	0.86	0.61	(7.31)	(6.07)
Diluted earnings (loss) per share(1)	0.40	0.77	0.53	(7.27)	(5.66)
2007					
Oil and gas sales	$13,175	$16,468	$17,050	$ 21,190	$ 67,883
Income before income taxes	5,390	6,799	5,974	6,732	24,895
Net income	3,814	4,637	3,561	4,873	16,885
Net income applicable to common stock	2,658	3,481	2,404	3,717	12,260
Basic earnings per share(1)	0.21	0.26	0.18	0.28	0.94
Diluted earnings per share(1)	0.21	0.26	0.18	0.28	0.93

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