RAM ENERGY RESOURCES INC
Form 10-Q
November 08, 2010

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

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

For the quarterly period ended September 30, 2010

OR

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

For the transition period from __________ to __________

Commission File Number: 000-50682

RAM Energy Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-0700684**
(State or other jurisdiction of incorporation or organization	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

5100 East Skelly Drive, Suite 650, Tulsa, OK 74135
(Address of principal executive offices)
(918) 663-2800
(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 twelve months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o No o

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

Large Accelerated Filer o	Accelerated Filer o	Non-Accelerated Filer o (Do not check if a smaller reporting company)	Smaller Reporting Company þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

At November 8, 2010, 78,636,524 shares of the Registrant s Common Stock were outstanding.

Third Quarter 2010 Form 10-Q Report
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ITEM 1 FINANCIAL STATEMENTS

RAM Energy Resources, Inc.
Condensed Consolidated Balance Sheets
(in thousands, except share and per share amounts)

	September 30, 2010 (unaudited)	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 29	$ 129
Accounts receivable:		
Oil and natural gas sales, net of allowance of $50 ($50 at December 31, 2009)	9,844	12,585
Joint interest operations, net of allowance of $479 ($641 at December 31, 2009)	547	1,303
Income taxes	119	
Other, net of allowance of $48 ($48 at December 31, 2009)	754	193
Derivative assets	2,385	
Prepaid expenses	1,027	1,970
Deferred tax asset	3,976	3,531
Inventory	3,372	3,900
Other current assets	911	27
Total current assets	22,964	23,638
PROPERTIES AND EQUIPMENT, AT COST:		
Proved oil and natural gas properties and equipment, using full cost accounting	729,441	702,502
Other property and equipment	9,928	9,337
	739,369	711,839
Less accumulated depreciation, amortization and impairment	(482,797)	(462,541)
Total properties and equipment	256,572	249,298
OTHER ASSETS:		
Deferred tax asset	32,061	31,573
Derivative assets	383	
Deferred loan costs, net of accumulated amortization of $4,490 ($2,924 at December 31, 2009)	3,131	4,697
Other	946	1,956
Total assets	$ 316,057	$ 311,162
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 18,335	$ 15,697
Oil and natural gas proceeds due others	9,638	10,113
Other	80	636

Accrued liabilities:		
Compensation	1,230	2,664
Interest	2,650	2,933
Income taxes	182	655
Other	336	10
Derivative liabilities		4,471
Asset retirement obligations	731	711
Long-term debt due within one year	124	126
Total current liabilities	33,306	38,016
DERIVATIVE LIABILITIES		358
LONG-TERM DEBT	247,012	246,041
ASSET RETIREMENT OBLIGATIONS	27,617	26,363
OTHER LONG-TERM LIABILITIES	10	10
COMMITMENTS AND CONTINGENCIES		900
STOCKHOLDERS EQUITY (DEFICIT):		
Common stock, $0.0001 par value, 100,000,000 shares authorized, 82,597,829 and 80,748,674 shares issued, 78,636,524 and 76,951,883 shares outstanding at September 30, 2010 and December 31, 2009, respectively	8	8
Additional paid-in capital	225,237	222,979
Treasury stock - 3,961,305 shares (3,796,791 shares at December 31,2009) at cost	(6,520)	(6,189)
Accumulated deficit	(210,613)	(217,324)
Stockholders equity (deficit)	8,112	(526)
Total liabilities and stockholders equity (deficit)	$ 316,057	$ 311,162

The accompanying notes are an integral part of these condensed consolidated financial statements.

RAM Energy Resources, Inc.

Condensed Consolidated Statements of Operations
(in thousands, except share and per share amounts)
(unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
REVENUES AND OTHER OPERATING INCOME:				
Oil and natural gas sales				
Oil	$ 18,290	$ 18,276	$ 56,898	$ 45,740
Natural gas	4,923	4,607	16,170	15,564
NGLs	3,250	2,999	10,461	7,134
Total oil and natural gas sales	26,463	25,882	83,529	68,438
Realized gains (losses) on derivatives	(1,213)	483	(2,818)	19,032
Unrealized gains (losses) on derivatives	1,782	(1,283)	6,136	(26,085)
Other	51	49	125	177
Total revenues and other operating income	27,083	25,131	86,972	61,562
OPERATING EXPENSES:				
Oil and natural gas production taxes	1,518	1,320	4,565	3,119
Oil and natural gas production expenses	8,571	9,772	25,153	28,976
Depreciation and amortization	6,782	7,909	20,387	24,377
Accretion expense	452	513	1,288	1,449
Impairment				47,613
Share-based compensation	813	539	2,284	1,632
General and administrative, overhead and other expenses, net of operator s overhead fees	2,932	4,247	10,694	12,337
Total operating expenses	21,068	24,300	64,371	119,503
Operating income (loss)	6,015	831	22,601	(57,941)
OTHER INCOME (EXPENSE):				
Interest expense	(5,767)	(5,561)	(17,116)	(12,770)
Interest income	20	40	24	69
Other income (expense)	(268)	10	293	(529)
EARNINGS (LOSS) BEFORE INCOME TAXES		(4,680)	5,802	(71,171)
INCOME TAX BENEFIT	(1,564)	(1,561)	(909)	(25,409)
Net earnings (loss)	$ 1,564	$ (3,119)	$ 6,711	$ (45,762)

BASIC EARNINGS (LOSS) PER SHARE	$ 0.02	$ (0.04)	$ 0.09	$ (0.61)
BASIC WEIGHTED AVERAGE SHARES OUTSTANDING	78,633,535	74,505,534	78,361,299	75,487,262
DILUTED EARNINGS (LOSS) PER SHARE	$ 0.02	$ (0.04)	$ 0.09	$ (0.61)
DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	78,633,535	74,505,534	78,361,299	75,487,262

The accompanying notes are an integral part of these condensed consolidated financial statements.

RAM Energy Resources, Inc.

Condensed Consolidated Statements of Cash Flows
(in thousands)
(unaudited)

	Nine months ended September 30, 2010	Nine months ended September 30, 2009
OPERATING ACTIVITIES:		
Net income (loss)	$ 6,711	$ (45,762)
Adjustments to reconcile net income (loss) to net cash provided by operating activities-		
Depreciation and amortization	20,387	24,377
Amortization of deferred loan costs and Senior Notes discount	1,566	1,120
Non-cash interest	2,336	829
Accretion expense	1,288	1,449
Impairment		47,613
Unrealized (gain) loss on derivatives and premium amortization	(3,859)	27,242
Deferred income tax benefit	(933)	(25,690)
Share-based compensation	2,284	1,632
(Gain) loss on disposal of other property, equipment and subsidiary	(38)	89
Other expense (income)	(574)	448
Changes in operating assets and liabilities-		
Accounts receivable	3,023	166
Prepaid expenses, inventory and other assets	1,598	1,137
Derivative premiums	(3,738)	(1,781)
Accounts payable and proceeds due others	1,603	(13,915)
Accrued liabilities and other	(1,717)	(15,468)
Restricted cash		16,000
Income taxes payable	(473)	(176)
Asset retirement obligations	(161)	(287)
Total adjustments	22,592	64,785
Net cash provided by operating activities	29,303	19,023
INVESTING ACTIVITIES:		
Payments for oil and natural gas properties and equipment	(27,476)	(21,728)
Proceeds from sales of oil and natural gas properties	478	6,156
Payments for other property and equipment	(721)	(504)
Proceeds from sales of other property and equipment	4	433
Net cash used in investing activities	(27,715)	(15,643)
FINANCING ACTIVITIES:		
Payments on long-term debt	(37,618)	(24,120)
Proceeds from borrowings on long-term debt	36,261	23,022
Payments for deferred loan costs		(2,324)

Stock repurchased		(331)		(6)
Net cash used in financing activities		(1,688)		(3,428)
DECREASE IN CASH AND CASH EQUIVALENTS		(100)		(48)
CASH AND CASH EQUIVALENTS, beginning of period		129		164
CASH AND CASH EQUIVALENTS, end of period	$	29	$	116
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for income taxes	$	616	$	457
Cash paid for interest	$	13,518	$	9,011
DISCLOSURE OF NON CASH INVESTING AND FINANCING ACTIVITIES:				
Asset retirement obligations	$	147	$	115
Payment-in-kind interest	$	2,336	$	829
Receipt of common stock for settlement of contingent receivable	$		$	2,134

The accompanying notes are an integral part of these condensed consolidated financial statements.

RAM Energy Resources, Inc.
Notes to unaudited condensed consolidated financial statements

A SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, ORGANIZATION AND BASIS OF PRESENTATION

1. *Basis of Financial Statements*

The accompanying unaudited condensed consolidated financial statements present the financial position at September 30, 2010 and December 31, 2009 and the results of operations and cash flows for the three and nine month periods ended September 30, 2010 and 2009 of RAM Energy Resources, Inc. and its subsidiaries (the Company). These condensed consolidated financial statements include all adjustments, consisting of normal and recurring adjustments, which, in the opinion of management, are necessary for a fair presentation of the financial position and the results of operations for the indicated periods. The results of operations for the three and nine months ended September 30, 2010 are not necessarily indicative of the results to be expected for the full year ending December 31, 2010. Reference is made to the Company s consolidated financial statements for the year ended December 31, 2009 included in the Company s Annual Report on Form 10-K, for an expanded discussion of the Company s financial disclosures and accounting policies.

2. *Nature of Operations and Organization*

The Company operates exclusively in the upstream segment of the oil and gas industry with activities including the drilling, completion, and operation of oil and gas wells. The Company conducts the majority of its operations in the states of Texas, Louisiana and Oklahoma.

3. *Use of Estimates*

The preparation of financial statements in conformity with accounting principles, generally accepted in the United States of America, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas reserves, amortization relating to oil and natural gas properties, asset retirement obligations, contingent litigation settlements, derivative instrument valuations and income taxes. The Company evaluates its estimates and assumptions on a regular basis. Estimates are based on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates used in preparation of the Company s financial statements. In addition, alternatives can exist among various accounting methods. In such cases, the choice of accounting method can have a significant impact on reported amounts.

4. *Earnings (Loss) per Common Share*

Basic earnings (loss) per share are computed by dividing net income or loss by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share reflect the potential dilution that could occur if dilutive stock unit options were exercised, calculated using the treasury stock method. A reconciliation of net income (loss) and weighted average shares used in computing basic and diluted net income (loss) per share is as follows for the three and nine months ended September 30 (in thousands, except share and per share amounts):

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Net income (loss)	$ 1,564	$ (3,119)	$ 6,711	$ (45,762)
Weighted average shares basic	78,633,535	74,505,534	78,361,299	75,487,262
Dilutive effect of units options				
Weighted average shares dilutive	78,633,535	74,505,534	78,361,299	75,487,262
Basic earnings (loss) per share	$ 0.02	$ (0.04)	$ 0.09	$ (0.61)
Diluted earnings (loss) per share	$ 0.02	$ (0.04)	$ 0.09	$ (0.61)

5. *Subsequent Events*

The Company evaluates events and transactions that occur after the balance sheet date but before the financial statements are filed with the U.S. Securities and Exchange Commission (SEC).

6. *New Accounting Pronouncements*

In January 2009, the Financial Accounting Standards Board (the FASB) issued guidance on fair value disclosures to enhance disclosures surrounding the transfers of assets in and out of Level 1 and Level 2, to present more detail surrounding asset activity for Level 3 assets and to clarify existing disclosures requirements. The new guidance is set forth in Topic 820 of the Accounting Standards Codification TM (the Codification) and was effective for the Company beginning January 1, 2010. Adoption of the guidance in the first quarter of 2010 did not impact the Company s financial position or results of operations.

B PROPERTIES AND EQUIPMENT

Under the full cost method of accounting, the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at 10% (the Ceiling Limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, and certain production-related and ad valorem taxes are deducted. In calculating future net revenues, prices and costs are held constant indefinitely, except for prices and costs that are fixed and determinable by existing contracts. The net book value is compared to the Ceiling Limitation on a quarterly and yearly basis. The excess, if any, of the net book value above the Ceiling Limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. At March 31, 2009, the net book value of the Company s oil and natural gas properties exceeded the Ceiling Limitation resulting in a reduction in the carrying value of the Company s oil and natural gas properties of $47.6 million. The after-tax effect of this reduction was $30.3 million. As of September 30, 2010 and 2009, the net book value of the Company s oil and natural gas properties did not exceed the Ceiling Limitation.

C LONG-TERM DEBT

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

	September 30, 2010	December 31, 2009
Credit facility	$ 246,569	$ 245,730
Accrued payment-in-kind interest	259	262
Installment loan agreements	308	175
	247,136	246,167
Less amount due within one year	124	126
	$ 247,012	$ 246,041

Credit Facility

In November 2007, in conjunction with the Company s Ascent acquisition, the Company entered into a new $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The facility includes a $250.0 million revolving credit facility and a $200.0 million term loan facility and an additional $50.0 million available under the term loan as requested by the Company and approved by the lenders. The initial amount of the $200.0 million term loan was advanced at closing. The borrowing base under the revolving credit facility initially was set at $175.0 million, a portion of which was advanced at the closing of the Ascent acquisition. Borrowings under the facility were used to refinance RAM Energy s existing indebtedness, fund the cash requirements in connection with the closing of the Ascent acquisition, and for working capital and other general corporate purposes. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the four-year term of the revolver, and initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The term loan provides for payments of interest only during its five-year term, with the initial interest rate being LIBOR plus 7.5%. Effective September 30, 2010, the borrowing base was redetermined at $165.0 million based on the value of the Company s proved reserves at June 30, 2010.

Advances under the facility are secured by liens on substantially all properties and assets of the Company and its subsidiaries. The loan agreement contains representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to total indebtedness. The Company is required to maintain commodity hedges with respect to not less than 50%, but not more than 85%, of the Company s projected monthly production volumes on a rolling 30-month basis, until the leverage ratio is less than or equal to 2.0 to 1.0.

On June 26, 2009, the Company entered into the Second Amendment to the credit facility. The Second Amendment amends certain definitions and certain financial and negative covenant terms providing greater flexibility for the Company through the remaining term of the facility. Additionally, the Second Amendment increased the interest rates applicable to borrowings under both the revolver and the term loan. Advances under the revolver will bear interest at LIBOR, with a minimum LIBOR rate, or floor, of 1.5%, plus a margin ranging from 2.25% to 3.0% based on a percentage of usage. The term loan will bear interest at LIBOR, also with a floor of 1.5%, plus a margin of 8.5%, and an additional 2.75% of payment-in-kind interest that will be added to the term loan principal balance on a monthly basis and paid at maturity. The Company was in compliance with all of the financial covenants under the credit facility at September 30, 2010. At September 30, 2010, $133.5 million was outstanding under the revolving credit facility and $113.3 million was outstanding under the term facility, including $0.3 million accrued payment-in-kind interest.

D CAPITAL STOCK

The Company had outstanding options to purchase up to 275,000 units at any time on or prior to May 11, 2009 at an exercise price of $9.90 per unit, with each unit consisting of one share of the Company s common stock and two warrants. All of the unit purchase options expired unexercised.

E INCOME TAXES

Under guidance contained in Topic 740 of the Codification, deferred taxes are determined by applying the provisions of enacted tax laws and rates for the jurisdictions in which the Company operates to the estimated future tax effects of the differences between the tax bases of assets and liabilities and their reported amounts in the Company s financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company estimates its annual effective income tax rate in recording its quarterly provision for income taxes in the various jurisdictions in which the Company operates. Statutory tax rate changes and other significant or unusual items are recognized as discrete items in the quarter in which they occur.

The Company has calculated an estimated effective tax rate for the current annual reporting period, excluding any discrete items, of 52% as of September 30, 2010. The estimated annual rate differs from the statutory rate primarily due to the estimate of state income taxes and non-deductible expenses for the period. Based upon the estimated effective tax rate, the Company recorded income tax expense of $3.1 million on pre-tax income of $5.8 million for the nine months ended September 30, 2010. Additionally, during the nine months ended September 30, 2010 the Company reduced the previously recorded valuation allowance by $4.0 million due to its estimate of taxable income that it projects will be generated in the near future and more likely than not result in the realization of its deferred tax assets. The reduction in the valuation allowance was recorded as a discrete item in the second quarter of 2010.

For the nine months ended September 30, 2009 the Company recorded an income tax benefit of $25.4 million on a pre-tax net loss of $71.2 million. Excluding the 2009 ceiling test impairment of $47.6 million and the related tax benefit of $17.3 million, the effective tax rate was 34% for the first nine months of 2009.

F COMMITMENTS AND CONTINGENCIES

Sacket v. Great Plains Pipeline Company, et al. This was a class action lawsuit on behalf of certain royalty owners in which RAM Energy, together with certain of its subsidiaries and affiliates, were defendants. In the lawsuit, the plaintiff alleged that the royalty payments to landowners for oil and natural gas produced from wells connected to a RAM Energy subsidiary s natural gas, oil and saltwater pipeline system in Woods, Alfalfa and Major Counties, Oklahoma, were calculated on a price that was lower than the price at which the production from the related wells were resold by the subsidiary. On March 5, 2009, the Court approved a settlement of the lawsuit and on April 4, 2009, the settlement became final.

During 2008, the Company recorded a contingent liability of $16.0 million for its share of the settlement amount and a receivable of $2.8 million in other current assets representing the value of escrowed shares, set aside by former stockholders of RAM Energy to cover this litigation, based on the closing price of $0.88 per share on December 31, 2008. The Company also recorded a charge to other expense of $13.2 million for the difference between the settlement liability and the value of the escrowed shares. During the first quarter of 2009, the Company recorded a charge to other expense of $0.4 million and adjusted the receivable from $2.8 million to $2.4 million to adjust the Fair Market Value of the escrowed shares to reflect the final settlement due of $0.74 per share.

Rathborne Land Company, et al., v. Ascent Energy Inc., et al. Ascent Energy Inc. and its Ascent Energy Louisiana, LLC subsidiary were sued in federal district court in Louisiana for lease cancellation and damages for failure to explore and develop the plaintiff s lease. By opinion dated December 31, 2008, the trial court found in favor of the plaintiff and against the defendants, and on June 1, 2009, the court entered judgment against the defendants in the amount of $4.6 million, which judgment was timely appealed to the United States Court of Appeals for the Fifth Circuit. Pursuant to the terms of the Ascent merger agreement, the Company s liability was limited to 50% of the first $1.8 million of any judgment rendered or settlement reached in the case, with the balance to be paid out of the escrow established at the closing of the merger. Accordingly, during the fourth quarter of 2008, the Company recorded a contingent liability of $0.9 million related to this litigation.

On June 23, 2010, the Fifth Circuit affirmed in part and reversed in part the trial court s judgment, effectively

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reducing the damage award to approximately $0.7 million. Due to the court s reduction of the damage award, the contingent liability related to this litigation was reduced to $0.4 million during the second quarter of 2010. On September 22, 2010, the case was settled with the Company owing $0.3 million of the settlement amount. The $0.4 million contingent liability was reduced to $0.3 million and classified as a current liability at September 30, 2010.

The Company is also involved in other legal proceedings and litigation in the ordinary course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company s financial position or results of operations.

G FAIR VALUE MEASUREMENTS

The Company measures the fair value of its derivative instruments according to the fair value hierarchy as set forth in Topic 820 of the Codification. Topic 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The fair value of the Company s net derivative assets as of September 30, 2010 was $2.8 million and the fair value of its net derivative liabilities as of December 31, 2009 was $4.8 million, based on Level 2 criteria. See Note H.

At September 30, 2010, the carrying value of cash, receivables and payables reflected in the Company s consolidated financial statements approximates fair value due to their short-term nature. Additionally, the carrying value of the Company s long-term debt under the credit facility approximates fair value because the credit facility carries a variable interest rate based on market interest rates. See Note C for discussion of long-term debt.

H DERIVATIVE CONTRACTS

The Company periodically utilizes various hedging strategies to manage the price received for a portion of its future oil and natural gas production to reduce exposure to fluctuations in oil and natural gas prices and to achieve a more predictable cash flow.

During 2010 and 2009, the Company entered into numerous derivative contracts to manage the impact of oil and natural gas price fluctuations and as required by the terms of its credit facility.

The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2010 and 2009 have been recorded in the statements of operations.

The Company s derivative positions at September 30, 2010, consisting of put/call collars and put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

	Crude Oil (Bbls)					Natural Gas (Mmbtu)				
	Floors		Ceilings			Floors		Ceilings		
Year	Per Day(1)	Price	Per Day(1)	Price	Months Covered	Per Day(1)	Price	Per Day(1)	Price	Months Covered
Collars										
2010	1,500	$ 55.00	1,500	$ 80.10	October - December	3,315	$ 5.00	3,315	$ 9.15	November - December
2011		$		$		6,219	$ 5.00	6,219	$ 9.48	January - September

	Bare Floors			Bare Floors		
Year	Per Day(1)	Price	Months Covered	Per Day(1)	Price	Months Covered
2010	2,000	$ 60.00	October - December	6,685	$ 4.75	October - December
2011	2,758	$ 60.00	January - December	836	$ 4.50	November - December
2012		$		1,243	$ 4.50	January - March

(1) Per day amounts are calculated based on a 365-day year for 2010 and 2011 and a 366-day year for 2012.

The Company estimates the fair value of its derivative instruments based on published forward commodity price curves as of the date of the estimate, less discounts to recognize present values. The Company estimates the fair value of its derivatives using a pricing model which also considers market volatility, counterparty credit risk and additional criteria in determining discount rates. See Note G. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The counterparty credit risk is determined by calculating the difference between the derivative counterparty s bond rate and published bond rates. The Company incorporates its credit risk when the derivative position is a liability by using its LIBOR spread rate.

Gross fair values of the Company s derivative instruments, prior to netting of assets and liabilities subject to a master netting arrangement, as of September 30, 2010 and December 31, 2009 and the amounts recorded in the consolidated statements of operations for the three and nine months ended September 30, 2010 and 2009 are as follows (in thousands):

CONSOLIDATED BALANCE SHEETS

Gross Assets and Liabilities	Balance Sheet Location	Fair Value As of September 30, 2010	Fair Value As of December 31, 2009
Current Assets Derivative assets	Current Assets - Derivative assets	$ 3,397	$
Current Assets Derivative assets	Current Liabilities - Derivative liabilities		413
Other Assets Derivative assets	Other Assets - Derivative assets	476	
Other Assets Derivative assets	Long-Term Liabilities - Derivative liabilities		200
Current Liabilities Derivative liabilities	Current Assets - Derivative assets	(1,012)	
Current Liabilities Derivative liabilities	Current Liabilities - Derivative liabilities		(4,884)
Long-Term Liabilities Derivative liabilities	Other Assets - Derivative assets	(93)	
Long-Term Liabilities Derivative liabilities	Long-Term Liabilities - Derivative liabilities		(558)
Total Derivatives Not Designated as Hedging Instruments		$ 2,768	$ (4,829)

CONSOLIDATED STATEMENTS OF OPERATIONS

Location	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Revenue Unrealized gains (losses) on derivatives	$ 1,782	$ (1,283)	$ 6,136	$ (26,085)
Revenue Realized gains (losses) on derivatives	$ (1,213)	$ 483	$ (2,818)	$ 19,032

I SHARE-BASED COMPENSATION

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation, as set forth in Topic 718 of the Codification. The guidance requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

On May 8, 2006, the Company s stockholders approved its 2006 Long-Term Incentive Plan (the Plan). The Company reserved a maximum of 2,400,000 shares of its common stock for issuances under the Plan. The Plan includes a provision that, at the request of a grantee, the Company may repurchase shares to satisfy the grantee s federal and state income tax withholding requirements. All repurchased shares will be held by the Company as treasury stock. On May 8, 2008, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2,400,000 to 6,000,000. On May 3, 2010, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 6,000,000 to 7,400,000. As of September 30, 2010, 1,960,271 shares of common stock remained reserved for issuance under the Plan.

As of September 30, 2010, the Company had $5.9 million of unrecognized compensation cost related to non-vested, share-based compensation awards granted under the Plan. That cost is expected to be recognized over a weighted-average period of two years. The related compensation expense recognized during the three and nine months ended September 30, 2010 was $0.8 million and $2.3 million, respectively, and during the three and nine months ended September 30, 2009 was $0.5 million and $1.6 million, respectively.

J- SUBSEQUENT EVENT

Disposition of Assets

On October 29, 2010, the Company executed a purchase and sale agreement to dispose of its North Texas Barnett Shale and Boonsville properties for $43.8 million in cash, subject to customary due diligence and other closing adjustments. The effective date of the divestiture is October 1, 2010 with the closing anticipated to occur in early December 2010. The assets to be sold represent 13% of the Company s year-end 2009 estimated proved reserves. Additionally, the assets to be sold represent approximately 8% and 9% of the Company s total oil and gas sales for the three and nine months ended September 30, 2010, respectively.

ITEM 2 MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS

General

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Louisiana and Oklahoma. Our producing properties are located in highly prolific basins with long histories of oil and natural gas operations.

Principal Properties

Our oil and natural gas assets are characterized by a combination of conventional and unconventional reserves and prospects. We have conventional reserves and production in three main onshore locations:

South Texas Starr, Wharton and Duval Counties, Texas (Developing Fields);

Electra/Burkburnett Wichita and Wilbarger Counties, Texas (Mature Oil Fields); and

Pontotoc County, Oklahoma (Mature Oil Fields).

Our unconventional reserves and prospects are primarily shale plays in the following areas:

North Texas Barnett Shale Jack and Wise Counties, Texas. This is our Tier 1 Barnett Shale acreage where we own interests in approximately 27,018 gross (6,594 net) acres (Developing Field); and

Appalachian Devonian Shale Cabell and Mason Counties, West Virginia. We own leasehold interests in approximately 52,740 gross (46,846 net) acres (Developing Field).

Net Production, Unit Prices and Costs

The following table presents certain information with respect to our oil and natural gas production, and prices and costs attributable to all oil and natural gas properties owned by us, for the three and nine months ended September 30, 2010. Average realized prices reflect the actual realized prices received by us, before and after giving effect to the results of our derivative contract settlements. Our derivative activities are financial, and our production of oil, natural gas liquids, or NGLs, and natural gas, and the average realized prices we receive from our production, are not affected by our derivative arrangements.

	Three months ended September 30, 2010	Nine months ended September 30, 2010
Production volumes:		
Oil (MBbls)	247	757
NGLs (MBbls)	91	280
Natural gas (MMcf)	1,215	3,714
Total (MBoe)	541	1,656
Average sale prices received:		
Oil (per Bbl)	$ 74.05	$ 75.16
NGLs (per Bbl)	$ 35.71	$ 37.36
Natural gas (per Mcf)	$ 4.05	$ 4.35
Total per Boe	$ 48.91	$ 50.44
Cash effect of derivative contracts:		
Oil (per Bbl)	$ (4.68)	$ (4.08)
NGLs (per Bbl)	$	$
Natural gas (per Mcf)	$ (0.05)	$ 0.07
Total per Boe	$ (2.24)	$ (1.70)
Average prices computed after cash effect of settlement of derivative contracts:		
Oil (per Bbl)	$ 69.37	$ 71.08
NGLs (per Bbl)	$ 35.71	$ 37.36
Natural gas (per Mcf)	$ 4.00	$ 4.42
Total per Boe	$ 46.67	$ 48.74
Cash expenses (per Boe):		
Oil and natural gas production taxes	$ 2.81	$ 2.76
Oil and natural gas production expenses	$ 15.84	$ 15.19
General and administrative	$ 5.42	$ 6.46
Interest	$ 8.15	$ 8.16
Taxes	$ 0.09	$ 0.37
Total per Boe	$ 32.31	$ 32.94
Cash flow per Boe	$ 14.36	$ 15.80

Acquisition, Development and Exploration Capital Expenditures

The following table presents information regarding our net costs incurred in our acquisitions of proved and unproved properties, and our development and exploration activities during the three and nine months ended September 30, 2010 (in thousands):

	Three months ended September 30, 2010	Nine months ended September 30, 2010
Development and exploratory costs	$ 8,400	$ 26,563
Proved property acquisition costs	410	913
Total costs incurred	$ 8,810	$ 27,476

During the quarter ended September 30, 2010, we participated in the drilling of 13 gross (13.0 net) development wells and 2 gross (2.0 net) exploration wells. Nine gross (9.0 net) development wells were capable of production, and one gross (1.0 net) exploration well was capable of production. Four gross (4.0 net) development wells and one gross (1.0 net) exploration well were in the process of being completed or waiting on completion as of September 30, 2010. In addition, 11 gross (5.2 net) wells drilled during previous quarters were capable of producing as of September 30, 2010, and five gross (4.6 net) wells drilled in previous quarters were in the process of being completed or waiting on completion as of September 30, 2010.

Results of Operations

Quarter Ended September 30, 2010 Compared to Quarter Ended September 30, 2009

Oil and natural gas sales increased $0.6 million, or 2%, to $26.5 million for the three months ended September 30, 2010, as compared to $25.9 million for the same period in 2009. This increase was driven by higher commodity prices during the 2010 period. Production volumes declined 14% as compared to the same period last year.

Production from our developing fields of South Texas, Barnett Shale and Appalachia in West Virginia decreased 26 MBoe in the third quarter due to normal production declines which were not offset by current drilling due to the unavailability of fracturing and stimulation crews and equipment in South Texas, which continued to delay initiation of production from wells drilled in our South Texas developing field. Drilling activity included one gross (1.0 net) exploration well in our South Texas field. Production from our mature oil fields of Electra/Burkburnett in North Texas and Allen/Fitts in Pontotoc County, Oklahoma decreased 44 MBoe in the third quarter primarily due to natural production declines and offline wells related to weather-related disruptions in the second quarter, which were gradually returned to production during the third quarter. Drilling activity in our mature oil fields included 13 gross (13.0 net) development wells in our Electra/Burkburnett field and one gross (1.0 net) exploration well. Production from our mature gas fields decreased 19 MBoe in the third quarter 2010 due to natural production declines. We did not drill any new wells in our Allen/Fitts fields or mature gas fields during this quarter.

The following tables summarize our oil and natural gas production volumes, average sales prices (without regard to derivative contract settlements) and period to period comparisons for the periods indicated:

	South Texas	Developing Fields Barnett Shale	Appalachia	Mature Oil Fields* Various	Mature Natural Gas Fields Various	Total
Three Months Ended September 30, 2010						
Aggregate Net Production						
Oil (MBbls)	11	1		205	30	247
NGLs (MBbls)	34	21		15	21	91
Natural Gas (MMcf)	511	127	12	61	504	1,215
MBoe	130	43	2	231	135	541
Three Months Ended September 30, 2009						
Aggregate Net Production						
Oil (MBbls)	12	2		233	31	278
NGLs (MBbls)	31	32		20	21	104
Natural Gas (MMcf)	525	195	21	135	612	1,488
MBoe	130	67	4	275	154	630
Change in MBoe		(24)	(2)	(44)	(19)	(89)
Percentage Change in MBoe	0.0%	-35.8%	-50.0%	-16.0%	-12.3%	-14.1%

* Includes Electra/Burkburnett, Allen/Fitts and Layton fields.

	Three months ended September 30, 2010	2009	Increase
Average sale prices:			
Oil (per Bbl)	$ 74.05	$ 65.74	12.6%
NGL (per Bbl)	$ 35.71	$ 28.84	23.8%
Natural gas (per Mcf)	$ 4.05	$ 3.10	30.6%
Per Boe	$ 48.91	$ 41.08	19.1%

The average realized sales prices increased substantially for the three months ended September 30, 2010, as compared to the same period in 2009. The average realized sales price for oil was $74.05 per barrel for the three months ended September 30, 2010, an increase of 13%, compared to $65.74 per barrel for the same period in 2009. The average realized sales price for NGLs was $35.71 for the three months ended September 30, 2010, an increase of 24%, compared to $28.84 per barrel for the same period in 2009. The average realized sales price for natural gas was $4.05 per Mcf for the three months ended September 30, 2010, an increase of 31%, compared to $3.10 per Mcf for the same period in 2009. The positive impact from the 19% increase in total average price per Boe in the third quarter of 2010 was sufficient to fully offset the impact of the decline in production, allowing oil and gas revenue for the third quarter to rise to $26.5 million compared to $25.9 million in the year-ago third quarter.

Realized and Unrealized Gain (Loss) from Derivatives. For the quarter ended September 30, 2010, our gain from derivatives was $0.6 million, compared to a loss of $0.8 million for the quarter ended September 30, 2009. Our gains and losses during these periods were the net result of recording actual contract settlements, the premiums for our derivative contracts, and unrealized gains and losses attributable to mark-to-market values of our derivative contracts at the end of the periods.

	Three months ended September 30,	
	2010	**2009**
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ (1,157)	$ (37)
Natural gas	(56)	520
Realized gains (losses)	(1,213)	483
Mark-to-market gains (losses):		
Oil	98	(105)
Natural gas	1,684	(1,178)
Unrealized gains (losses)	1,782	(1,283)
Realized and unrealized gains (losses)	$ 569	$ (800)

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $1.5 million for the quarter ended September 30, 2010, compared to $1.3 million for the comparable quarter of the previous year. Most production taxes are based on realized prices at the wellhead, while Louisiana production taxes are based on volumes for natural gas and values for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. The increase is due principally to higher commodity prices in the 2010 period. Additionally, retroactive severance tax refunds were granted during the third quarter of 2009. As a percentage of oil and natural gas sales, our oil and natural gas production taxes increased to 6% for the quarter ended September 30, 2010, as compared to 5% for the quarter ended September 30, 2009.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $8.6 million for the quarter ended September 30, 2010, a decrease of $1.2 million, or 12%, from the $9.8 million for the quarter ended September 30, 2009. The decrease was due primarily to decreased production volumes in the 2010 period. For the quarter ended September 30, 2010, our oil and natural gas production expense was $15.84 per Boe compared to $15.51 per Boe for the quarter ended September 30, 2009, an increase of 2%. As a percentage of oil and natural gas sales, oil and natural gas production expense was 32% for the quarter ended September 30, 2010, as compared to 38% for the quarter ended September 30, 2009. This decrease results from a combination of declines in production and higher oil and natural gas sales caused by higher commodity prices in the 2010 period.

Amortization and Depreciation Expense. Our amortization and depreciation expense decreased $1.1 million, or 14%, for the quarter ended September 30, 2010, compared to the quarter ended September 30, 2009. On an equivalent basis, our amortization of the full-cost pool of $6.5 million was $12.06 per Boe for the quarter ended September 30, 2010, a decrease per Boe of 1% compared to $7.7 million, or $12.17 per Boe for the quarter ended September 30, 2009.

Accretion Expense. Topic 410 of the Codification, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded $0.5 million for the quarter ended September 30, 2010, unchanged from the quarter ended September 30, 2009.

Share-Based Compensation. From time to time, our Board of Directors grants restricted stock awards under our 2006 Long-Term Incentive Plan. Each of these grants vests in equal increments over the vesting period provided for the particular award. All currently unvested awards provide for vesting periods of from one to five years. The share-based compensation expense attributable to these grants is calculated using the closing price per share on each of the grant dates and will be recognized over their respective vesting periods. For the quarter ended September 30, 2010, we recognized a total of $0.8 million share-based compensation expense, compared to $0.5 million from the quarter ended September 30, 2009. The increase was primarily due to additional grants and increased stock price during the 2010 period.

General and Administrative Expense. For the quarter ended September 30, 2010, our general and administrative expense was $2.9 million, compared to $4.2 million for the quarter ended September 30, 2009, a decrease of $1.3 million, or 31%. The decrease results primarily from lower employee-related costs and professional fees in the 2010 period.

Other Expense. For the third quarter of 2010, we recorded a charge of $0.3 million to other expense relating to pipe inventory write-off.

Interest Expense. We recorded interest expense of $5.8 million for the quarter ended September 30, 2010, as compared to $5.6 million for the third quarter of the previous year. The increase in interest expense was due to higher average outstanding borrowings throughout the 2010 period. Our blended interest rate was 8.2% in the third quarter of 2010 compared to 8.9% in the 2009 period.

Income Taxes. For the three months ended September 30, 2010 and 2009, we recorded income tax benefit of $1.6 million.

Nine Months Ended September 30, 2010 Compared to the Nine Months Ended September 30, 2009

Oil and natural gas sales increased $15.1 million, or 22% to $83.5 million for the nine months ended September 30, 2010, as compared to $68.4 million for the same period in 2009. This increase was driven by higher commodity prices in the 2010 period. Production volumes decreased 15% for the nine months ended September 30, 2010, as compared to the same period last year.

Production from our developing fields of South Texas, Barnett Shale, and Appalachia in West Virginia decreased 60 MBoe for the nine months ended September 30, 2010, due to normal production declines which were not offset by current drilling due to the unavailability of fracturing and stimulation crews and equipment in South Texas, which continued to delay initiation of production from wells drilled in our South Texas developing field. Drilling activity in our developing fields included 11 gross (5.0 net) development wells and one gross (1.0 net) exploration well. Production from our mature oil fields of Electra/Burkburnett in North Texas and Allen/Fitts in Pontotoc County, Oklahoma decreased 165 MBoe in the first nine months of 2010, primarily due to weather-related interruptions in both the first and second quarters of 2010 and natural production declines. Drilling activity in our mature oil fields included 42 gross (40.8 net) development wells and two gross (2.0 net) exploration wells. Production from our mature gas fields decreased 57 MBoe for the nine months ended September 30, 2010, due to natural production declines. Drilling activity included one gross (0.2 net) exploration well in our mature gas fields during this period.

The following tables summarize our oil and natural gas production volumes, average sales prices (without regard to derivative contract settlements) and period to period comparisons, including the effect on our oil and natural gas sales, for the periods indicated:

	Developing Fields			Mature Oil Fields*	Mature Natural Gas Fields	
	South Texas	**Barnett Shale**	**Appalachia**	**Various**	**Various**	**Total**
Nine Months Ended September 30, 2010						
Aggregate Net Production						
Oil (MBbls)	33	4		637	83	757
NGLs (MBbls)	94	80		44	62	280
Natural Gas (MMcf)	1,495	463	40	177	1,539	3,714
MBoe	376	161	6	711	402	1,656
Nine Months Ended September 30, 2009						
Aggregate Net Production						
Oil (MBbls)	45	6	1	726	80	858
NGLs (MBbls)	87	94		62	60	303
Natural Gas (MMcf)	1,547	604	66	530	1,911	4,658
MBoe	390	201	12	876	459	1,938
Change in MBoe	(14)	(40)	(6)	(165)	(57)	(282)
Percentage Change in MBoe	-3.6%	-19.9%	-50.0%	-18.8%	-12.4%	-14.6%

* Includes Electra/Burkburnett, Allen/Fitts and Layton fields.

	Nine months ended September 30,		
	2010	**2009**	**Increase**
Average sale prices:			
Oil (per Bbl)	$75.16	$53.31	41.0%
NGLs (per Bbl)	$37.36	$23.54	58.7%
Natural gas (per Mcf)	$ 4.35	$ 3.34	30.2%
Per Boe	$50.44	$35.31	42.8%

The average realized sales prices increased substantially for the nine months ended September 30, 2010, as compared to the same period in 2009. The average realized sales price for oil was $75.16 per barrel for the nine months ended September 30, 2010, an increase of 41%, compared to $53.31 per barrel for the same period in 2009. The average realized sales price for NGLs was $37.36 for the nine months ended September 30, 2010, an increase of 59%, compared to $23.54 per barrel for the same period in 2009. The average realized sales price for natural gas was $4.35 per Mcf for the nine months ended September 30, 2010, an increase of 30%, compared to $3.34 per Mcf for the same period in 2009. The positive impact from the 43% increase in total average price per Boe in the nine months ended September 30, 2010, more than offset the decline in production, allowing oil and gas revenue in the first nine months of 2010 to grow to $83.5 million compared to $68.4 million in the prior year period.

Realized and Unrealized Gain (Loss) from Derivatives. For the nine months ended September 30, 2010, our gain from derivatives was $3.3 million compared to a loss of $7.1 million for the nine months ended September 30, 2009. Our gains and losses during these periods were the net result of recording actual contract settlements, the premiums for our derivative contracts, and unrealized gains and losses attributable to mark-to-market values of our derivative contracts at the end of the periods. Contributing to the realized gains for the nine months ended September 30, 2009, was the sale of natural gas contracts during the second quarter of 2009.

	Nine months ended September 30,	
	2010	**2009**
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ (3,088)	$ 6,103
Natural gas	270	12,929
Realized gains (losses)	(2,818)	19,032
Mark-to-market gains (losses):		
Oil	3,577	(19,316)
Natural gas	2,559	(6,769)
Unrealized gains (losses)	6,136	(26,085)
Realized and unrealized gains (losses)	$ 3,318	$ (7,053)

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $4.6 million for the nine months ended September 30, 2010, compared to $3.1 million for the comparable nine months of the previous year. The increase is due principally to higher commodity prices in the 2010 period. Production taxes vary by state. Most production taxes are based on realized prices at the wellhead, while Louisiana production tax is based on volumes for natural gas and value for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5% for the nine months ended September 30, 2010 and 2009.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $25.2 million for the nine months ended September 30, 2010, a decrease of $3.8 million, or 13%, from the $29.0 million for the nine months ended September 30, 2009. For the nine months ended September 30, 2010, our oil and natural gas production expense was $15.19 per Boe compared to $14.95 per Boe for the nine months ended September 30, 2009, an increase of 2%. As a percentage of oil and natural gas sales, oil and natural gas production expense was 30% for the nine months ended September 30, 2010, as compared to 42% for the nine months ended September 30, 2009. This decrease results from a combination of declines in production and the increase in oil and natural gas sales due to the higher commodity prices in the 2010 period.

Amortization and Depreciation Expense. Our amortization and depreciation expense decreased $4.0 million, or 16%, for the nine months ended September 30, 2010, compared to the nine months ended September 30, 2009. On an equivalent basis, our amortization of the full-cost pool of $19.6 million was $11.83 per Boe for the nine months ended September 30, 2010, a decrease per Boe of 3% compared to $23.6 million, or $12.22 per Boe for the nine months ended September 30, 2009. This rate decrease per Boe resulted primarily from lower capitalized costs subsequent to the asset impairment writedown in the first quarter of 2009.

Accretion Expense. Topic 410 of the Codification, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded $1.3 million for the nine months ended September 30, 2010, compared to $1.4 million for the first nine months in 2009.

Impairment Charge. We incurred a $47.6 million impairment of the carrying value of our oil and gas properties during the first nine months of 2009. The impairment of our oil and gas properties was solely due to a reduction in the tax affected estimated present value of future net revenues, caused by the dramatic decline in commodity prices, from our proved oil and gas reserves between December 31, 2008 and March 31, 2009. We incurred no impairment for the nine months ended September 30, 2010.

Share-Based Compensation. From time to time, our Board of Directors grants restricted stock awards under our 2006 Long-Term Incentive Plan. Each of these grants vests in equal increments over the vesting period provided for the particular award. All currently unvested awards provide for vesting periods of from one to five years. The share-based compensation on these grants was calculated using the closing price per share on each of the grant dates and the total share-based compensation on all these grants will be recognized over their respective vesting periods. For the nine months ended September 30, 2010, we recognized a total of $2.3 million share-based compensation compared to $1.6 million for the nine months ended September 30, 2009. The increase was primarily due to additional grants and increased stock price during the 2010 period.

General and Administrative Expense. For the nine months ended September 30, 2010, our general and administrative expense was $10.7 million, compared to $12.3 million for the nine months ended September 30, 2009, a decrease of $1.6 million, or 13%. The decrease results from the lower employee-related costs and professional fees in the 2010 period.

Other Income (Expense). For the nine months ended September 30, 2010, other income was $0.3 million as compared to other expense of $0.5 million for the nine months ended September 30, 2009. For the 2010 period, we reduced a contingency litigation accrual by $0.6 million related to settlement of pending litigation offset by a charge relating to pipe inventory write-off. For the nine months ended September 30, 2009, we recorded a charge to other expense of $0.5 million primarily for expense related to settlement of pending litigation.

Interest Expense. We recorded interest expense of $17.1 million for the nine months ended September 30, 2010, as compared to $12.8 million for the first nine months of the previous year. The increase in interest expense was due to higher average outstanding borrowings throughout the 2010 period. Additionally, interest rates were higher in the 2010 period as set forth in the Second Amendment to our credit facility executed June 26, 2009. Our blended interest rate was 8.2% for the nine months ended September 30, 2010, compared to 6.8% in the 2009 period.

Income Taxes. For the nine months ended September 30, 2010, we recorded income tax expense of $3.1 million on pre-tax income of $5.8 million. In addition, we recorded a $4.0 million tax benefit resulting from a decrease in our valuation allowance as a discrete item during the quarter ended June 30, 2010. For the nine months ended September 30, 2009, we recorded an income tax benefit of approximately $8.1 million on a pre-tax net loss of $23.6 million, exclusive of the discrete item recorded during the first quarter of 2009 for the ceiling test impairment of $47.6 million and the related tax benefit of $17.3 million.

Liquidity and Capital Resources

As of September 30, 2010, we had $31.4 million of nominal availability under our revolving credit facility; however, because of the amount of our Modified EBITDA for the preceding four fiscal quarters, the financial covenants in our credit facility would have limited us to $15.3 million of additional borrowings as of September 30, 2010. We will be unable to borrow the full amount of our borrowing base until our Modified EBITDA for the preceding four fiscal quarters equals or exceeds $60.0 million. At September 30, 2010, we had $247.1 million of indebtedness outstanding, including $113.3 million under our term loan facility (which includes $0.3 million of accrued payment-in-kind interest), $133.5 million under our revolving credit facility and $0.3 million in other indebtedness. As of September 30, 2010, we had an accumulated deficit of $210.6 million and a working capital deficit of $10.3 million.

Credit Facility. In November 2007, in conjunction with the Ascent acquisition, we entered into a new $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The new facility, which replaced our previous $300.0 million facility, includes a $250.0 million revolving credit facility, a $200.0 million term loan facility, and an additional $50.0 million available under the term loan as requested by us and approved by the lenders. The entire amount of the $200.0 million term loan was advanced at closing. The borrowing base under the revolving credit facilit