RAM ENERGY RESOURCES INC
Form 10-Q
August 09, 2011

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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 June 30, 2011

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

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 August 9, 2011, 79,087,298 shares of the Registrant s Common Stock were outstanding.

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ITEM 1 FINANCIAL STATEMENTS

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

	June 30, 2011 (unaudited)	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 454	$ 37
Accounts receivable:		
Oil and natural gas sales, net of allowance of $50 ($50 at December 31, 2010)	9,657	9,797
Joint interest operations, net of allowance of $479 ($479 at December 31, 2010)	724	631
Other, net of allowance of $34 ($48 at December 31, 2010)	152	155
Derivative assets		1,340
Prepaid expenses	1,030	1,657
Deferred tax asset	7,422	3,526
Inventory	3,812	3,382
Other current assets	384	4
Total current assets	23,635	20,529
PROPERTIES AND EQUIPMENT, AT COST:		
Proved oil and natural gas properties and equipment, using full cost accounting	702,668	689,472
Other property and equipment	10,438	10,072
	713,106	699,544
Less accumulated depreciation, amortization and impairment	(499,994)	(489,634)
Total properties and equipment	213,112	209,910
OTHER ASSETS:		
Deferred tax asset	29,058	31,001
Deferred loan costs, net of accumulated amortization of $381 ($5,012 at December 31, 2010)	6,622	2,609
Other	978	952
Total assets	$ 273,405	$ 265,001
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 13,807	$ 17,149
Oil and natural gas proceeds due others	9,455	9,414
Other	155	452
Accrued liabilities:		
Compensation	1,794	1,948
Interest	502	2,448
Income taxes	334	699

Other	640	10
Derivative liabilities	1,576	
Asset retirement obligations	352	639
Long-term debt due within one year	146	127
Total current liabilities	28,761	32,886
DERIVATIVE LIABILITIES	3,079	203
LONG-TERM DEBT	205,289	196,965
ASSET RETIREMENT OBLIGATIONS	31,504	30,770
OTHER LONG-TERM LIABILITIES	10	10
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY (DEFICIT):		
Common stock, $0.0001 par value, 100,000,000 shares authorized, 83,386,299 and 82,597,829 shares issued, 79,120,829 and 78,386,983 shares outstanding at June 30, 2011 and December 31, 2010, respectively	8	8
Additional paid-in capital	227,720	226,042
Treasury stock - 4,265,470 shares (4,210,846 shares at December 31,2010) at cost	(7,084)	(6,976)
Accumulated deficit	(215,882)	(214,907)
Stockholders equity	4,762	4,167
Total liabilities and stockholders equity	$ 273,405	$ 265,001

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

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RAM Energy Resources, Inc.
Condensed Consolidated Statements of Operations
(in thousands, except share and per share amounts)
(unaudited)

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
REVENUES AND OTHER OPERATING INCOME:				
Oil and natural gas sales				
Oil	$ 22,783	$ 19,120	$ 43,195	$ 38,608
Natural gas	2,812	4,818	5,704	11,247
NGLs	2,523	3,280	4,938	7,211
Total oil and natural gas sales	28,118	27,218	53,837	57,066
Realized losses on derivatives	(2,098)	(707)	(1,262)	(1,605)
Unrealized gains (losses) on derivatives	10,728	2,419	(4,225)	4,354
Other	34	38	85	74
Total revenues and other operating income	36,782	28,968	48,435	59,889
OPERATING EXPENSES:				
Oil and natural gas production taxes	1,478	1,453	2,889	3,047
Oil and natural gas production expenses	8,174	8,662	16,549	16,582
Depreciation and amortization	5,196	6,891	10,469	13,605
Accretion expense	412	454	814	836
Share-based compensation	686	785	1,355	1,471
General and administrative, overhead and other expenses, net of operator s overhead fees	3,935	3,992	7,813	7,762
Total operating expenses	19,881	22,237	39,889	43,303
Operating income	16,901	6,731	8,546	16,586
OTHER INCOME (EXPENSE):				
Interest expense	(3,563)	(5,714)	(10,113)	(11,349)
Interest income	3	2	3	4
Loss on interest rate derivatives	(362)		(495)	
Other income (expense)	(801)	570	(753)	561
INCOME (LOSS) BEFORE INCOME TAXES	12,178	1,589	(2,812)	5,802
INCOME TAX PROVISION (BENEFIT)	3,242	(1,140)	(1,837)	655
Net income (loss)	$ 8,936	$ 2,729	$ (975)	$ 5,147
BASIC INCOME (LOSS) PER SHARE	$ 0.11	$ 0.03	$ (0.01)	$ 0.07

BASIC WEIGHTED AVERAGE SHARES OUTSTANDING		78,834,159		78,446,305		78,598,387		78,222,925
DILUTED INCOME (LOSS) PER SHARE	$	0.11	$	0.03	$	(0.01)	$	0.07
DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING		78,834,159		78,446,305		78,598,387		78,222,925

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)

	Six months ended June 30, 2011	2010
OPERATING ACTIVITIES:		
Net income (loss)	$ (975)	$ 5,147
Adjustments to reconcile net income (loss) to net cash provided by operating activities-		
Depreciation and amortization	10,469	13,605
Amortization of deferred loan costs	2,990	1,044
Non-cash interest	362	1,543
Accretion expense	814	836
Unrealized (gain) loss on commodity derivatives, net of premium amortization	5,474	(2,997)
Unrealized loss on interest rate derivatives	418	
Deferred income tax provision (benefit)	(1,953)	268
Share-based compensation	1,355	1,471
Gain on disposal of other property and equipment	(22)	(41)
Other income		(550)
Changes in operating assets and liabilities-		
Accounts receivable	49	3,237
Prepaid expenses, inventory and other assets	(208)	657
Derivative premiums	(111)	(2,866)
Accounts payable and proceeds due others	(3,553)	1,028
Accrued liabilities and other	(1,459)	(1,004)
Income taxes payable	(365)	(177)
Asset retirement obligations	(242)	
Total adjustments	14,018	16,054
Net cash provided by operating activities	13,043	21,201
INVESTING ACTIVITIES:		
Payments for oil and natural gas properties and equipment	(13,500)	(18,666)
Proceeds from sales of oil and natural gas properties	462	478
Payments for other property and equipment	(469)	(358)
Proceeds from sales of other property and equipment	11	4
Net cash used in investing activities	(13,496)	(18,542)
FINANCING ACTIVITIES:		
Payments on long-term debt	(223,185)	(24,576)
Proceeds from borrowings on long-term debt	231,166	22,132
Payments for deferred loan costs	(7,003)	
Stock repurchased	(108)	(326)

Net cash provided by (used in) financing activities		870		(2,770)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		417		(111)
CASH AND CASH EQUIVALENTS, beginning of period		37		129
CASH AND CASH EQUIVALENTS, end of period	$	454	$	18
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for income taxes	$	481	$	565
Cash paid for interest	$	8,706	$	9,107
DISCLOSURE OF NON CASH INVESTING AND FINANCING ACTIVITIES:				
Asset retirement obligations	$	(129)	$	118

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

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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 June 30, 2011 and December 31, 2010 and the results of operations for the three and six month periods ended June 30, 2011 and 2010, and cash flows for the six month periods ended June 30, 2011 and 2010 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 six months ended June 30, 2011 are not necessarily indicative of the results to be expected for the full year ending December 31, 2011. Reference is made to the Company s consolidated financial statements for the year ended December 31, 2010 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 natural gas industry with activities including the drilling, completion, and operation of oil and natural gas wells. The Company conducts the majority of its operations in the states of Texas, Oklahoma and Louisiana. The Company also owns and operates oil and natural gas properties in New Mexico, Mississippi and West Virginia.

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. ***Income (Loss) per Common Share***

Basic and diluted income (loss) per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding for the period. A reconciliation of net income (loss) and weighted average shares used in computing basic and diluted net income (loss) per share are as follows (in thousands, except share and per share amounts):

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	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Net income (loss)	$ 8,936	$ 2,729	$ (975)	$ 5,147
Weighted average shares basic	78,834,159	78,446,305	78,598,387	78,222,925
Dilutive effect				
Weighted average shares dilutive	78,834,159	78,446,305	78,598,387	78,222,925
Basic income (loss) per share	$ 0.11	$ 0.03	$ (0.01)	$ 0.07
Diluted income (loss) per share	$ 0.11	$ 0.03	$ (0.01)	$ 0.07

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 May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). This pronouncement was issued to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between U.S. GAAP and IFRS. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements particularly for level 3 fair value measurements. This update is effective for reporting periods beginning on or after December 15, 2011. The adoption of ASU 2011-04 is not expected to have a significant impact on the Company s consolidated financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income. ASU 2011-05 eliminates the option to report other comprehensive income and its components in the statement of changes in stockholders equity and requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. This update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Adoption of ASU 2011-05 will not have an impact on the Company s consolidated 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 changes 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 June 30, 2011 and 2010, 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):

	June 30, 2011	December 31, 2010
Credit facilities	$ 205,000	$ 196,521
Accrued payment-in-kind interest		221
Installment loan agreements	435	350
	205,435	197,092
Less amount due within one year	146	127
	$ 205,289	$ 196,965

Credit Facilities

In March 2011, the Company entered into new credit facilities. The new facilities, which replaced the Company s previous facility, include a $250.0 million first lien revolving credit facility and a $75.0 million second lien term loan facility. SunTrust Bank is the administrative agent for the revolving credit facility, and Guggenheim Corporate Funding LLC is the agent for the term loan facility. The borrowing base under the revolving credit facility at June 30, 2011 was $150.0 million. The borrowing base is reviewed and redetermined effective March 31 and September 30 of each year, and between scheduled redeterminations upon request. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the five-year term of the revolver, and bear interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The term loan credit facility provides for payments of interest only during its 5.5-year term, with the interest rate being LIBOR plus 9.0% with a 2.0% LIBOR floor, or if in any period the Company elects to pay a portion of the interest under its term loan in kind, then the interest rate will be LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to the principal. At June 30, 2011, $130.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the term loan credit facility.

Advances under the new credit facilities are secured by liens on substantially all properties and assets of the Company and its subsidiaries. The new credit facilities contain representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on the Company s capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to indebtedness. The Company was in compliance with all of its covenants in the credit facilities at June 30, 2011. The Company is required to maintain commodity hedges on a rolling basis for the first 12 months of not less than 60%, but not more than 85%, and for the next 18 months of not less than 50%, but not more than 85%, of projected quarterly production volumes, until the leverage ratio is less than or equal to 1.5 to 1.0. During June 2011, the Company entered into the First Amendment to the revolving credit facility. The First Amendment amended certain definitions affecting covenant calculations and modified the terms of the Company s natural gas derivative counterparty requirements.

The Company s previous credit facility entered into in November 2007, included a $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The previous credit facility included 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. Funds advanced under the previous revolving credit facility initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The previous term loan provided for payments of interest only during its term, with the initial interest rate being LIBOR plus 7.5%. The borrowing base under the previous revolving credit facility was $145.0 million at December 31, 2010.

During June 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 loans. Advances under the revolver bore 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 bore 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 was added to the term loan principal balance on a monthly basis and paid at maturity. The Company was in compliance with all its covenants in the credit facility at December 31, 2010. At December 31, 2010, $116.5 million was outstanding under the revolving credit facility and $80.2 million was outstanding under the term facility, including $0.2 million accrued payment-in-kind interest. Due to refinancing of the Company s outstanding debt prior to the issuance of the December 31, 2010 financial statements, the current portion of existing debt at December 31, 2010 was considered long-term. As previously noted, the Company entered into new credit facilities in March 2011. The proceeds from the new facilities were used to repay the previous facility. The Company expensed the remaining debt issuance costs associated with the previous facility totaling approximately $2.7 million in the first quarter of 2011.

D 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. During the three and six months ended June 30, 2011, the Company analyzed and made no adjustment to the valuation allowance. During the three months ended June 30, 2010 the Company reduced the previously recorded valuation allowance by $4.0 million due to its estimate of taxable income that it projected would 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.

The Company has calculated an estimated effective tax rate for the current annual reporting period, excluding any discrete items, of 66% as of June 30, 2011. 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 benefit of $1.8 million on pre-tax loss of $2.8 million for the six months ended June 30, 2011. For the six months ended June 30, 2010 the Company recorded an income tax expense of $4.7 million on a pre-tax income of $5.8 million.

E COMMITMENTS AND CONTINGENCIES

The Company is involved in 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.

In May of 2008, the Company drilled the Woolley #1-23 well in Oklahoma. On July 21, 2008 the Oklahoma Corporation Commission (the OCC) entered a forced pooling order for the Woolley #1-23 well and the Company acquired all of the working interests attributable to those parties who did not elect to participate in the drilling of the Woolley #1-23 well. Subsequent to the pooling, certain predecessors in interest that were erroneously omitted from the forced pooling order disputed the pooling order and sought a determination that they were entitled to share in the pooled acreage. The OCC determined that the omitted predecessors in interest were not entitled to share in the pooled acreage; however, the ruling of the OCC was reversed on appeal. As a result, the Company lost a portion of its working interest in the Woolley #1-23 well and in the McAlester formation of the 40-acre tract in which the well is located. During the second quarter of 2011, the Company recorded a charge to other expense of $0.8 million, a reduction in proved oil and gas properties of $0.2 million and a liability of $0.6 million to record the estimated settlement of the dispute.

F 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 liabilities as of June 30, 2011 was $4.7 million and the fair value of the Company s net derivative assets as of December 31, 2010 was $1.1 million, based on Level 2 criteria. See Note G.

At June 30, 2011, the carrying value of cash, accounts receivable and accounts payable 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 facilities approximates fair value because the credit facilities carry a variable interest rate based on market interest rates. See Note C for discussion of long-term debt.

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G DERIVATIVE CONTRACTS

The Company periodically utilizes various hedging strategies to achieve a more predictable cash flow. Various derivative instruments are used to manage the price received for a portion of the Company s future oil and natural gas production and interest rate swaps are used to manage the interest rate paid for a portion of the Company s outstanding debt.

During 2011 and 2010, 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 facilities. During the first quarter of 2011, the Company also entered into interest rate swaps to manage the impact of interest rate fluctuations. The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2011 and 2010 have been recorded in the statements of operations.

The Company s oil and natural gas derivative positions at June 30, 2011, 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	
Period	Per Day	Price	Per Day	Price	Period	Per Day	Price	Per Day	Price
Q3 11	2,250	$ 80.00	2,250	$ 105.00	Q3 11	5,000	$ 5.00		
Q4 11	2,150	$ 80.00	2,150	$ 105.00	Q4 11	7,304	$ 4.18		
Q1 12	2,000	$ 80.00	2,000	$ 105.00	Q1 12	7,000	$ 4.36		
Q2 12	2,000	$ 80.00	2,000	$ 105.00	Q2 12	5,000	$ 4.00	5,000	$ 6.00
Q3 12	1,900	$ 92.63	1,900	$ 105.66	Q3 12	5,000	$ 4.00	5,000	$ 6.00
Q4 12	1,750	$ 92.14	1,750	$ 104.83	Q4 12				
Q1 13	1,800	$ 95.28	1,800	$ 101.39	Q1 13				
Q2 13	1,650	$ 95.00	1,650	$ 99.93	Q2 13				
Q3 13	1,600	$ 95.00	1,600	$ 99.94	Q3 13				
Q4 13	1,550	$ 95.00	1,550	$ 99.71	Q4 13				
Q1 14	1,600	$ 95.00	1,600	$ 100.03	Q1 14				
Q2 14	1,500	$ 95.00	1,500	$ 99.13	Q2 14				

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The Company s interest rate derivative positions at June 30, 2011, consisting of interest rate swaps, are shown in the following table:

	Interest Rate Swaps [1]			
Year	Notional Amount (in millions)	Fixed Rate	Counterparty Floating Rate [2]	Months Covered
2011	$ 50	2.51%	3 Month LIBOR	July December
			3 Month LIBOR	January
2012	$ 50	2.51%		December
			3 Month LIBOR	January
2013	$ 50	2.51%		December
2014	$ 50	2.51%	3 Month LIBOR	January March

(1) Settlement is paid to the Company if the counterparty floating rate exceeds the fixed rate and settlement is paid by the Company if the counterparty floating rate is below the fixed rate. Settlement is calculated as the difference in the fixed rate and the counterparty rate.

(2) Subject to a minimum rate of 2%.

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 F.

To determine the fair value of the Company s oil and natural gas derivative instruments, the discount rate used in the discounted cash flow projections was based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The counterparty credit risk was 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 June 30, 2011 and December 31, 2010 and the consolidated statements of operations for the three and six months ended June 30, 2011 and 2010 are as follows (in thousands):

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CONSOLIDATED BALANCE SHEETS

Gross Assets and Liabilities		Balance Sheet Location	Fair Value As of June 30, 2011 (unaudited)	Fair Value As of December 31, 2010
Current Assets	Oil and natural gas derivative assets	Current Assets - Derivative assets	$	$ 1,904
Current Assets	Oil and natural gas derivative assets	Current Liabilities - Derivative liabilities	713	
Other Assets	Oil and natural gas derivative assets	Long-Term Liabilities - Derivative liabilities	81	207
Current Liabilities	Oil and natual gas derivative liabilities	Current Assets - Derivative assets		(564)
Current Liabilities	Oil and natual gas derivative liabilities	Current Liabilities - Derivative liabilities	(2,021)	
Current Liabilities	Interest rate swaps derivative liabilities	Current Liabilities - Derivative liabilities	(268)	
Long-Term Liabilities	Oil and natural gas derivative liabilities	Long-Term Liabilities - Derivative liabilities	(2,999)	(410)
Long-Term Liabilities	Interest rate swaps derivative liabilities	Long-Term Liabilities - Derivative liabilities	(161)	
Total Derivatives Not Designated as Hedging Instruments			$ (4,655)	$ 1,137

CONSOLIDATED STATEMENTS OF OPERATIONS

Income Statement Location		Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Type of Derivative
Revenue	Unrealized gains (losses) on derivatives	$ 10,728	$ 2,419	$ (4,225)	$ 4,354	Oil and natural gas derivatives - unrealized
Revenue	Realized losses on derivatives	$ (2,098)	$ (707)	$ (1,262)	$ (1,605)	Oil and natural gas derivatives - realized
Other Income (Expense) - Loss on interest rate derivatives		$ (296)	$	$ (418)	$	Interest rate derivatives - unrealized

Other Income (Expense) - Loss on interest rate derivatives	$	(66)	$		$	(77)	$		Interest rate derivatives - realized

During April 2011, pursuant to the Company s new credit facilities entered into in March 2011, the Company was required to reduce the volume of its existing crude oil and natural gas derivatives so it would not exceed the maximum allowable volumes for future production periods and to novate derivative contracts to counterparties that are lenders within the new credit facilities. During the second quarter of 2011, the Company recognized $0.9 million in realized losses on the unwinding of the excess crude oil and natural gas derivatives and the $0.5 million in fees paid to complete the novation, both of which are included in realized gains and losses on derivatives in the income statement.

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H 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 June 30, 2011, 1,171,801 shares of common stock remained reserved for issuance under the Plan.

As of June 30, 2011, the Company had $4.8 million of unrecognized compensation related to common stock 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 six months ended June 30, 2011 was $0.8 million and $1.6 million, respectively, and during the three and six months ended June 30, 2010 was $0.8 million and $1.5 million, respectively. During the three and six months ended June 30, 2011, $0.7 million and $1.4 million, respectively of recognized compensation expense was recorded as compensation expense and $0.1 million and $0.2 million, respectively was recorded as capitalized internal costs.

In May 2011, the Company granted 1,530,500 Stock Appreciation Rights (SARs) under the Plan. The exercise price of the SARs issued is the closing price of the Company s stock on the date of grant, which was $1.73 per share on a weighted average basis. Compensation expense related to the SARs is based on fair value re-measured at each reporting period and recognized over the vesting period (generally four years). As of June 30, 2011, the fair value calculation resulted in no compensation expense recognized for the second quarter of 2011. The SARs expire ten years from date of grant and upon exercise. The Company will settle the SARs in cash, net of the applicable taxes.

The Company uses the Black-Scholes option pricing model to compute the fair value of the SARs. The following assumptions were used in calculating fair value:

The risk-free interest rate is based on the zero coupon United States Treasury yield for the expected life of the grant.

The dividend yield on the Company s common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

The volatility of the Company s common stock is based on volatility of the market price of the Company s common stock over a period of time equal to the expected term and ending on the grant date.

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

Principal Properties

Our principal oil and natural gas properties are located in the following fields:

Texas: La Copita (Starr County), Electra/Burkburnett (Wichita and Wilbarger Counties);

Oklahoma: Fitts-Allen (Pontotoc and Seminole Counties); and

Louisiana: Lake Enfermer (Lafourche Parish).

We also own and operate other oil and natural gas properties in Texas, Oklahoma, Louisiana, New Mexico, Mississippi and West Virginia.

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 six months ended June 30, 2011. 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.

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	Three months ended June 30, 2011		Six months ended June 30, 2011	
Production volumes:				
Oil (MBbls)		226		448
NGLs (MBbls)		44		91
Natural gas (MMcf)		660		1,370
Total (MBoe)		380		767
Average sale prices received:				
Oil (per Bbl)	$	100.81	$	96.42
NGLs (per Bbl)	$	57.34	$	54.26
Natural gas (per Mcf)	$	4.26	$	4.16
Total per Boe	$	73.99	$	70.19
Cash effect of derivative contracts:				
Oil (per Bbl)	$	(8.65)	$	(6.63)
NGLs (per Bbl)	$		$	
Natural gas (per Mcf)	$	(0.22)	$	1.25
Total per Boe	$	(5.52)	$	(1.65)
Average prices computed after cash effect of settlement of derivative contracts:				
Oil (per Bbl)	$	92.16	$	89.79
NGLs (per Bbl)	$	57.34	$	54.26
Natural gas (per Mcf)	$	4.04	$	5.41
Total per Boe	$	68.47	$	68.54
Expenses (per Boe):				
Oil and natural gas production taxes	$	3.89	$	3.77
Oil and natural gas production expenses	$	21.51	$	21.58
Amortization of full-cost pool	$	13.01	$	13.00
General and administrative	$	10.36	$	10.19
Cash interest	$	8.82	$	11.35
Cash taxes	$	1.33	$	0.63

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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 six months ended June 30, 2011 (in thousands):

	Three months ended June 30, 2011	Six months ended June 30, 2011
Development and exploratory costs	$ 7,657	$ 13,053
Proved property acquisition costs	223	447
Total costs incurred	$ 7,880	$ 13,500

During the quarter ended June 30, 2011, we participated in the drilling of ten gross (9.2 net) development wells and five gross (5.0 net) exploration wells. Nine gross (8.2 net) development wells were capable of production. One gross (1.0 net) development well was in the process of testing as of June 30, 2011. Five gross (5.0 net) exploration wells were either testing or waiting on completion and/or equipment at June 30, 2011.

Results of Operations

Quarter Ended June 30, 2011 Compared to Quarter Ended June 30, 2010

As we concentrate our holdings into areas that align with our objectives, we have determined to report our operations by state, rather than by field as was reported in previous years. The following tables summarize our oil and natural gas production volumes, average sale prices (without regard to derivative contract settlements) and period-to-period comparisons for the periods indicated:

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Three Months Ended June 30, 2011					
Aggregate Net Production					
Oil (MBbls)	128	74	16	8	226
NGLs (MBbls)	38	2		4	44
Natural Gas (MMcf)	412	107	105	36	660
MBoe	234	94	33	19	380

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Three Months Ended June 30, 2010					
Aggregate Net Production					
Oil (MBbls)	142	82	22	7	253
NGLs (MBbls)	85	2		4	91
Natural Gas (MMcf)	774	224	192	40	1,230
MBoe	356	121	54	18	549
Change in MBoe	(122)	(27)	(21)	1	(169)
Percentage change in MBoe	-34.3%	-22.3%	-38.9%	5.6%	-30.8%

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	Three months ended June 30,		
	2011	**2010**	**Increase**
Average sale prices:			
Oil (per Bbl)	$ 100.81	$ 75.57	33.4%
NGL (per Bbl)	$ 57.34	$ 36.04	59.1%
Natural gas (per Mcf)	$ 4.26	$ 3.92	8.7%
Per Boe	$ 73.99	$ 49.58	49.2%

In December 2010, we sold assets located in Texas and Oklahoma for net proceeds including post-closing adjustments of $48.8 million. The following table provides pro forma results for 2010 excluding those sold properties to assist our description of results of operations:

	Three months ended June 30, 2010		
	Actual	Sold Assets	Pro Forma
Oil and natural gas sales (in thousands):			
Oil	$ 19,120	$ 346	$ 18,774
Natural gas	4,818	1,244	3,574
NGLs	3,280	1,291	1,989
Total oil and natural gas sales	$ 27,218	$ 2,881	$ 24,337
Production expenses (in thousands):			
Oil and natural gas production taxes	$ 1,453	$ 125	$ 1,328
Oil and natural gas production expenses	$ 8,662	$ 454	$ 8,208
Production volumes:			
Texas (Mboe)	356	86	270
Oklahoma (Mboe)	121	15	106
Other (Mboe)	72		72
Total production (Mboe)	549	101	448

Oil and natural gas sales increased $0.9 million, or 3%, to $28.1 million for the three months ended June 30, 2011, as compared to $27.2 million for the three months ended June 30, 2010. Excluding asset sales, oil and natural gas sales would have increased by $3.8 million for the three months ended June 30, 2011, as compared to the same period in 2010. This increase was driven by higher commodity prices during the 2011 period, partially offset by decreased production.

Production volumes decreased 31% as compared to the same period last year. Excluding the activities related to the asset divestitures, our production volume would have decreased 15% as compared to the same period last year primarily due to shut-in of one well as a result of a major workover in Louisiana and normal production declines. Production from our Texas fields decreased 36 MBoe in the second quarter, excluding asset sales, due to a decline in well performance in our South Texas gas properties and from normal production declines. Drilling activity included eight gross (8.0 net) development wells which were capable of production in our Texas fields. Production from our Oklahoma fields decreased 12 MBoe in the second quarter, excluding asset sales, primarily due to natural production declines. Drilling activity in Oklahoma included one gross (0.2 net) development well and five gross (5.0 net) exploratory wells. Production from our Louisiana fields decreased 21 MBoe in the second quarter 2011 due to a shut-in of one well and normal production declines. We did not drill any new wells in our Louisiana fields during the second quarter of 2011.

The average realized sales prices on a Boe basis increased substantially for the three months ended June 30, 2011, as compared to the same period in 2010. The average realized sales price for oil was $100.81 per barrel for the three months ended June 30, 2011, an increase of 33%, compared to $75.57 per barrel for the same period in 2010. The average realized sales price for NGLs was $57.34 per barrel for the three months ended June 30, 2011, an increase of 59%, compared to $36.04 per barrel for the same period in 2010. The average realized sales price for natural gas was $4.26 per Mcf for the three months ended June 30, 2011, an increase of 9%, compared to $3.92 per Mcf for the same period in 2010. The positive impact from the 49% increase in total average price per Boe in the second quarter of 2011 more than offset the impact of asset sales and normal production declines, allowing oil and natural gas sales for the second quarter to grow to $28.1 million compared to $27.2 million in the prior year period.

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We recorded income before income taxes of $12.2 million for the quarter ended June 30, 2011, an increase of $10.6 million, as compared to income before income taxes of $1.6 million for the quarter ended June 30, 2010. Excluding unrealized gains on derivatives of $10.7 million, our adjusted income before income taxes for the quarter ended June 30, 2011 was $1.5 million. Excluding unrealized gains on derivatives of $2.4 million, our adjusted loss before income taxes for the quarter ended June 30, 2010 was $0.8 million.

Realized and Unrealized Gain (Loss) from Commodities Derivatives. For the quarter ended June 30, 2011, our gain from derivatives was $8.6 million, compared to $1.7 million for the quarter ended June 30, 2010. 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. During the quarter ended June 30, 2011, we recognized $0.9 million in realized losses on the unwinding of the excess crude oil and natural gas derivatives and $0.5 million in fees paid to complete the novation of derivative contracts to counterparties that are lenders within our new credit facilities, both of which are included in realized gains and losses on derivatives and required under the terms of the new credit facilities.

	Three months ended June 30,	
	2011	**2010**
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ (1,955)	$ (943)
Natural gas	(143)	236
Realized losses	(2,098)	(707)
Mark-to-market gains (losses):		
Oil	10,508	3,350
Natural gas	220	(931)
Unrealized gains	10,728	2,419
Realized and unrealized gains	$ 8,630	$ 1,712

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $1.5 million for the quarter ended June 30, 2011, compared to $1.3 million, excluding asset sales, 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 primarily to higher commodity prices in the 2011 period. As a percentage of oil and natural gas sales, our oil and natural gas production taxes were approximately 5% for each of the quarters ended June 30, 2011 and 2010.

Oil and Natural Gas Production Expense. Our oil and natural gas production expense was $8.2 million for each of the quarters ended June 30, 2011 and 2010, excluding asset sales for the quarter ended June 30, 2010. Our oil and natural gas production expense was $21.51 per Boe compared to $15.78 per Boe for the quarter ended June 30, 2010, an increase of 36%. The increase per Boe is primarily due to the asset sales, as the sold assets in 2010 were predominantly shale gas producing assets which had relatively lower lease operating expenses per Boe. As a percentage of oil and natural gas sales, oil and natural gas production expense was 29% for the quarter ended June 30, 2011, as compared to 32% for the quarter ended June 30, 2010. This decrease is due to higher oil and natural gas sales due to higher commodity prices in the 2011 period.

Amortization and Depreciation Expense. Our amortization and depreciation expense decreased $1.7 million, or 25%, for the quarter ended June 30, 2011, compared to the quarter ended June 30, 2010. The decrease was a result of a decrease in production during the 2011 period, offset by a higher depletion rate per Boe. On an equivalent basis, our amortization of the full-cost pool of $4.9 million was $13.01 per Boe for the quarter ended June 30, 2011, compared to $6.6 million, or $12.06 per Boe, for the quarter ended June 30, 2010.

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 $0.4 million for the quarter ended June 30, 2011, compared to $0.5 million for the quarter ended June 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 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. In May 2011, our Board of Directors awarded stock appreciation rights (SARs) under our 2006 Long-Term Incentive Plan. Share-based compensation expense attributable to these awards is based on the fair value re-measured at each reporting period and recognized over the four-year vesting period. The fair value calculation resulted in no compensation expense recognized for the three months ended June 30, 2011. For the quarter ended June 30, 2011, we recognized a total of $0.8 million share-based compensation related to restricted stock awards, the same as the year ago quarter. During the three months ended June 30, 2011, $0.7 million of recognized compensation was recorded as compensation expense and $0.1 million was recorded as capitalized internal costs.

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General and Administrative Expense. For the quarter ended June 30, 2011, our general and administrative expense was $3.9 million, compared to $4.0 million for the quarter ended June 30, 2010, a decrease of $0.1 million, or 1%. The decrease was primarily due to lower employee related expenses in the 2011 period.

Interest Expense. We recorded interest expense of $3.6 million for the quarter ended June 30, 2011, as compared to $5.7 million for the second quarter of the previous year. The decrease in interest expense was due to lower interest rates and lower average outstanding borrowings throughout the 2011 period. Our blended interest rate was 6.2% in the second quarter of 2011 compared to 8.2% in the 2010 period.

Loss on Interest Rate Derivatives. We incurred $0.4 million net realized and unrealized loss attributable to mark-to-market value of interest rate swaps in the second quarter of 2011. We had no interest rate derivatives in effect in the year ago quarter.

Other Income (Expense). For the three months ended June 30, 2011, our other expense was $0.8 million, compared to other income of $0.6 million for the three months ended June 30, 2010. For the quarter ended June 30, 2011, we were party to a lawsuit and incurred approximately $0.8 million in litigation expenses. For the three months ended June 30, 2010, we reduced a contingency accrual by $0.6 million related to settlement of pending litigation.

Income Taxes. For the three months ended June 30, 2011, we recorded income tax expense of $3.2 million on a pre-tax income of $12.2 million. For the three months ended June 30, 2010, we recorded income tax expense of $2.9 million on a pre-tax net income of $1.6 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 three months ended June 30, 2010.

Six Months Ended June 30, 2011 Compared to the Six Months Ended June 30, 2010

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

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Six Months Ended June 30, 2011					
Aggregate Net Production					
Oil (MBbls)	253	148	32	15	448
NGLs (MBbls)	79	5		7	91
Natural Gas (MMcf)	856	187	258	69	1,370
MBoe	474	184	75	34	767

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Six Months Ended June 30, 2010					
Aggregate Net Production					
Oil (MBbls)	291	163	39	17	510
NGLs (MBbls)	177	5		7	189
Natural Gas (MMcf)	1,638	436	347	78	2,499
MBoe	741	240	97	37	1,115
Change in MBoe	(267)	(56)	(22)	(3)	(348)
Percentage change in MBoe	-36.0%	-23.3%	-22.7%	-8.1%	-31.2%

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	Six months ended June 30,		Increase/
	2011	**2010**	**(Decrease)**
Average sale prices:			
Oil (per Bbl)	$ 96.42	$ 75.70	27.4%
NGLs (per Bbl)	$ 54.26	$ 38.15	42.2%
Natural gas (per Mcf)	$ 4.16		