UNIT CORP
Form 10-Q
August 04, 2009

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended June 30, 2009

OR

[ ] 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 1-9260]

UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	73-1283193
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)
7130 South Lewis, Suite 1000, Tulsa, Oklahoma	74136
(Address of principal executive offices)	(Zip Code)

(918) 493-7700
(Registrant's telephone number, including area code)

None
(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 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [x] No [ ]

Indicate by check mark 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 [ ] No [ ]

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. (Check one):

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
[x]	[ ]	[ ]	[ ]

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

Yes [ ]   No [x]

As of July 31, 2009, 47,516,104 shares of the issuer's common stock were outstanding.

FORM 10-Q
UNIT CORPORATION

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Forward-Looking Statements

This document contains "forward-looking statements" – meaning, statements related to future, not past, events. In this context, forward-looking statements often address our expected future business and financial performance, and often contain words such as "expect," "anticipate," "intend," "plan," "believe," "seek," or "will." Forward-looking statements by the nature address matters that are, to different degrees, uncertain. For us, some of the particular uncertainties that could adversely or positively affect our future results include: our belief regarding our liquidity; our expectation and how we intend to fund our capital expenditures; changes in the demand for and the prices of oil and natural gas; the liquidity of our customers; the behavior of financial markets, including fluctuations in interest and commodity and equity prices; strategic actions, including acquisitions and dispositions; future integration of acquired businesses; future financial performance of industries which we serve, including, without limitation, the energy industries; our belief that the final outcome of our legal proceedings will not materially affect our financial results; and numerous other matters of a national, regional and global scale, including those of a political, economic, business and competitive nature. These uncertainties may cause our actual future results to be materially different than those expressed in our forward-looking statements. We do not undertake to update our forward-looking statements.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2009	December 31, 2008
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 957	$ 584
Restricted cash	20	20
Accounts receivable, net of allowance for doubtful accounts of $4,893 at June 30, 2009 and $4,893 at December 31, 2008	95,427	192,408
Materials and supplies	10,695	9,923
Current derivative assets (Note 8)	49,166	52,177
Current income tax receivable	4,798	11,768
Prepaid expenses and other	15,862	19,705
Total current assets	176,925	286,585
Property and equipment:		
Drilling equipment	1,192,820	1,172,655
Oil and natural gas properties, on the full cost method:		
Proved properties	2,186,912	2,090,623
Undeveloped leasehold not being amortized	168,804	160,034
Gas gathering and processing equipment	169,190	169,402
Transportation equipment	31,978	33,611
Other	22,738	22,484
	3,772,442	3,648,809
Less accumulated depreciation, depletion, amortization and impairment	1,810,759	1,447,157
Net property and equipment	1,961,683	2,201,652
Goodwill	62,808	62,808
Other intangible assets, net	7,409	9,384
Non-current derivative assets (Note 8)	7,142	5,218
Other assets	17,436	16,219
Total assets	$ 2,233,403	$ 2,581,866

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

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	June 30, 2009	December 31, 2008
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 50,042	$ 129,755
Accrued liabilities	42,930	51,659
Contract advances	1,073	2,889
Current portion of derivative liabilities (Note 8)	5,204	1,481
Current portion of other liabilities (Note 4)	10,640	10,615
Total current liabilities	109,889	196,399
Long-term debt	111,000	199,500
Long-term derivative liabilities (Note 8)	2,066	1,780
Other long-term liabilities (Note 4)	75,139	74,027
Deferred income taxes	406,469	477,061
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 47,518,000 and 47,255,964 shares issued, respectively	9,369	9,325
Capital in excess of par value	380,024	367,000
Accumulated other comprehensive income	31,419	33,284
Retained earnings	1,108,028	1,223,490
Total shareholders' equity	1,528,840	1,633,099
Total liabilities and shareholders' equity	$ 2,233,403	$ 2,581,866

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

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UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 49,883	$ 151,228	$ 138,582	$ 298,475
Oil and natural gas	89,601	164,299	178,505	294,301
Gas gathering and processing	23,233	54,800	45,376	99,023
Other income (expense), net	1,357	(180)	2,673	(290)
Total revenues	164,074	370,147	365,136	691,509
Expenses:				
Contract drilling:				
Operating costs	29,779	78,278	80,109	152,739
Depreciation	10,261	16,988	22,880	32,352
Oil and natural gas:				
Operating costs	17,249	30,657	42,065	58,258
Depreciation, depletion and amortization	26,149	38,988	64,155	74,703
Impairment of oil and natural gas properties (Note 2)	—	—	281,241	—
Gas gathering and processing:				
Operating costs	19,199	45,164	39,876	80,236
Depreciation and amortization	4,110	3,663	8,171	7,144
General and administrative	5,493	6,726	11,582	13,251
Interest, net	61	273	538	1,093
Total operating expenses	112,301	220,737	550,617	419,776
Income (loss) before income taxes	51,773	149,410	(185,481)	271,733
Income tax expense (benefit):				
Current	1,247	9,688	1,247	25,135
Deferred	18,495	45,594	(71,266)	75,406
Total income taxes	19,742	55,282	(70,019)	100,541
Net income (loss)	$ 32,031	$ 94,128	$ (115,462)	$ 171,192
Net income (loss) per common share:				
Basic	$ 0.68	$ 2.02	$ (2.46)	$ 3.68
Diluted	$ 0.68	$ 2.00	$ (2.46)	$ 3.65

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	$ (115,462)	$ 171,192
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	95,743	114,491
Impairment of oil and natural gas properties (Note 2)	281,241	—
Unrealized loss on derivatives	2,940	—
Deferred tax expense (benefit)	(71,266)	75,406
Other	5,012	9,316
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	96,981	(23,005)
Accounts payable	8,567	(24,899)
Material and supplies inventory	(772)	(4,486)
Accrued liabilities	(4,105)	8,009
Contract advances	(1,816)	(4,085)
Other – net	11,779	(1,551)
Net cash provided by operating activities	308,842	320,388
INVESTING ACTIVITIES:		
Capital expenditures	(193,326)	(304,859)
Proceeds from disposition of assets	11,361	2,628
Other - net	—	(214)
Net cash used in investing activities	(181,965)	(302,445)
FINANCING ACTIVITIES:		
Borrowings under line of credit	71,100	129,100
Payments under line of credit	(159,600)	(146,900)
Proceeds from exercise of stock options	17	2,138
Tax benefit from stock options	—	746
Book overdrafts	(38,021)	(3,166)
Net cash used in financing activities	(126,504)	(18,082)
Net increase (decrease) in cash and cash equivalents	373	(139)
Cash and cash equivalents, beginning of period	584	1,076
Cash and cash equivalents, end of period	$ 957	$ 937

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands)			
Net income (loss)	$ 32,031	$ 94,128	$ (115,462)	$ 171,192
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $(8,038), ($24,911), $21,368 and ($38,205)	(15,052)	(42,418)	33,953	(65,082)
Reclassification - derivative settlements, net of tax of ($11,855), $5,186, ($21,702) and $5,185	(19,340)	8,828	(35,894)	8,827
Ineffective portion of derivatives, net of tax of $27, zero, $43 and zero	48	—	76	—
Comprehensive income (loss)	$ (2,313)	$ 60,538	$ (117,327)	$ 114,937

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this quarterly report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company," "Unit," "we," "our" and "us" refer to Unit Corporation, a Delaware corporation, and its subsidiaries and affiliates, except as otherwise clearly indicated or as the context otherwise requires.

The accompanying interim condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 24, 2009, for the year ended December 31, 2008.

In the opinion of management, the accompanying condensed consolidated financial statements contain all normal, recurring adjustments necessary to fairly state the following:

- Balance Sheets at June 30, 2009 and December 31, 2008;
- Statements of Operations for the three and six months ended June 30, 2009 and 2008; and
- Cash Flows for the six months ended June 30, 2009 and 2008.

All intercompany transactions have been eliminated. In addition, management has evaluated and disclosed all material subsequent events through August 4, 2009, which is the date the financial statements in this quarterly report are filed on Form 10-Q.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States which requires us to make estimates and assumptions that affect the amounts reported in our condensed consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Results for the three and six months ended June 30, 2009 and 2008 are not necessarily indicative of the results to be realized for the full year in the case of 2009, or that we realized for the full year of 2008. With respect to our unaudited financial information for the three and six month periods ended June 30, 2009 and 2008, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards for a review of that information. Its separate report, dated August 4, 2009, which is included in this quarterly report, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for its report on the unaudited financial information because that report is not a "report" or a "part" of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 –OIL AND NATURAL GAS PROPERTIES

Under the full cost ceiling test rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. Companies using the full cost method are required to use the unescalated prices in effect as of the end of each fiscal quarter to calculate the discounted future revenues. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which the excess occurs, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.

We recorded a non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ended March 31, 2009 as a result of a decline in commodity prices as compared to those existing at year end 2008. At June 30, 2009 commodity prices were at levels that did not require us to take a write-down of our oil and natural gas properties. However should prices, including the discounted value of our commodity hedges, after June 30, 2009 drop to levels at or below those existing at March 31, 2009 an additional write-down of the carrying value of our oil and natural gas properties could be required in future periods.

Derivative instruments qualifying as cash flow hedges were included in the computation of limitation on capitalized costs in the March 31, 2009 and June 30, 2009 ceiling test calculations and the effect was a $197.9 million and a $127.1 million, respectively, pre-tax increase in the discounted net cash flows of our oil and natural gas properties. At June 30, 2009, without the benefit of the discounted value of our commodity hedges, we would have been required to recognize an impairment to our full cost pool of approximately $14.6 million pre-tax ($9.1 million, net of tax). Our qualifying cash flow hedges as of March 31, 2009 and June 30, 2009, which consisted of swaps and collars, covered 30.3 Bcfe and 33.2 Bcfe in 2009 and 2010, respectively as of March 31 and covered 20.2 Bcfe and 35.4 Bcfe in 2009 and 2010, respectively as of June 30. Our oil and natural gas hedging activities are discussed in Note 8 of our Notes to Condensed Consolidated Financial Statements.

NOTE 3 - EARNINGS PER SHARE

Information related to the calculation of earnings (loss) per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended June 30, 2009:			
Basic earnings per common share	$ 32,031	47,008	$ 0.68
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	350	—
Diluted earnings per common share	$ 32,031	47,358	$ 0.68
For the three months ended June 30, 2008:			
Basic earnings per common share	$ 94,128	46,587	$ 2.02
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	417	(0.02)
Diluted earnings per common share	$ 94,128	47,004	$ 2.00

The number of stock options and stock appreciation rights (SARs) (and their average exercise price) not included in the above computation because their option exercise prices were greater than the average market price of our common stock was:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
Stock options and SARs	362,717	28,000
Average Exercise Price	$ 47.66	$ 73.26

	Income/(Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the six months ended June 30, 2009:			
Basic earnings (loss) per common share	$ (115,462)	46,965	$ (2.46)
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	—	—
Diluted earnings (loss) per common share	$ (115,462)	46,965	$ (2.46)
For the six months ended June 30, 2008:			
Basic earnings per common share	$ 171,192	46,534	$ 3.68
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	354	(0.03)
Diluted earnings per common share	$ 171,192	46,888	$ 3.65

Due to the net loss for the six months ended June 30, 2009, approximately 300,000 weighted average shares related to stock options, restricted stock and SARs were antidilutive and were excluded from the earnings per share calculation above. The number of stock options and SARs (and their average exercise price) not included in the above computation because their option exercise prices were greater than the average market price of our common stock was:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Stock options and SARs	376,717	56,000
Average Exercise Price	$ 46.94	$ 67.83

NOTE 4 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

As of the dates in the table, long-term debt consisted of the following:

	June 30, 2009	December 31, 2008
	(In thousands)	
Revolving credit facility, with interest of 2.4% at June 30, 2009 and 3.2% at December 31, 2008	$ 111,000	$ 199,500
Less current portion	—	—
Total long-term debt	$ 111,000	$ 199,500

On December 23, 2008, we entered into a First Amendment to our existing First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of $400.0 million maturing on May 24, 2012. This amendment increased the lenders' commitment by $50.0 million to an aggregate of $325.0 million. Borrowings under the Credit Facility are limited to a commitment amount that we can elect. As of June 30, 2009, the commitment amount was $325.0 million. We are charged a commitment fee of 0.375 to 0.50 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility and $478,125 associated with the December 23, 2008 First Amendment, which are being amortized over the life of the agreement. The average interest rate for the second quarter and first six months of 2009, which includes the effect of our interest rate swaps, was 3.6% and 3.8%. At June 30, 2009 and July 31, 2009, borrowings were $111.0 million and $80.0 million, respectively.

The lenders' aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The current borrowing base is $475.0 million per the April 1, 2009 redetermination. We or the lenders may request a onetime special redetermination of the borrowing base amount between each scheduled redetermination. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid on three days prior notice to the administrative agent and on our payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which in no event will be less than LIBOR plus 1.00%, payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At June 30, 2009, $108.5 million of our then outstanding borrowings of $111.0 million were subject to LIBOR.

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The Credit Facility prohibits:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The Credit Facility also requires that we have at the end of each quarter:

- consolidated net worth of at least $900 million;
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

As of June 30, 2009, we were in compliance with all the covenants contained in the Credit Facility.

Based on the borrowing rates currently available to us for debt with similar terms and maturities and consideration of our non-performance risk, long-term debt at June 30, 2009 approximates its fair value.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	June 30, 2009	December 31, 2008
	(In thousands)	
Plugging liability	$ 50,586	$ 49,230
Workers' compensation	24,560	23,473
Separation benefit plans	5,520	6,435
Gas balancing liability	3,364	3,364
Deferred compensation plan	1,749	2,030
Retirement agreements	—	110
	85,779	84,642
Less current portion	10,640	10,615
Total other long-term liabilities	$ 75,139	$ 74,027

Estimated annual principal payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning July 1, 2009 through 2014 are $10.6 million, $12.4 million, $114.2 million, $2.4 million and $1.8 million, respectively.

NOTE 5 – ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) we are required to record the fair value of liabilities associated with the retirement of long-lived assets. Our oil and natural gas wells are required to be plugged and abandoned when the oil and natural gas reserves in the wells are depleted or the wells are no longer able to produce. Under FAS 143, the plugging and abandonment expense for a well is recorded in the period in which the liability is incurred (at the time the well is drilled or acquired). We do not have any assets restricted for settling these well plugging liabilities.

The following table shows certain information regarding our well plugging liability:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands)	
Plugging liability, January 1:	$ 49,230	$ 33,191
Accretion of discount	1,250	866
Liability incurred	2,162	1,298
Liability settled	(2,071)	(364)
Revision of estimates	15	85
Plugging liability, June 30:	50,586	35,076
Less current portion	968	735
Total long-term plugging liability	$ 49,618	$ 34,341

NOTE 6 - NEW ACCOUNTING PRONOUNCEMENTS

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied on to prepare reserves estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based on the first-of-month posted price for each month in the prior twelve-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our consolidated financial statements.

Interim Disclosures about Fair Value of Financial Instruments. In April 2009, the Financial and Accounting Standards Board (FASB) issued FASB Staff Position (FSP) Statement No. 107-1 and Accounting Principles Board (APB) 28-1 (collectively, FSP FAS 107-1), “Interim Disclosures about Fair Value of Financial Instruments.” FSP FAS 107-1 amends FAS 107, “Disclosures about Fair Value of Financial Instruments,” to require an entity to provide disclosures about fair value of financial instruments in interim financial information. The FSP FAS 107-1 also amends APB Opinion 28, “Interim Financial Reporting,” to require those disclosures in summarized financial information at interim reporting periods. Under FSP FAS 107-1, we will be required to include disclosures about the fair value of our financial instruments whenever we issue financial information for interim reporting periods. In addition, we will be required to disclose in the body or in the accompanying notes of our summarized financial information for interim reporting periods and in our financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 is effective for periods ending after June 15, 2009. We have included the required disclosure in Note 4 of our Notes to Condensed Consolidated Financial Statements.

Subsequent Events. In May 2009, the FASB issued FASB Statement No. 165 (FAS165), “Subsequent Events”. FAS165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. FAS165 provides:

- The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;
- The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and

- The disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

FAS165 is effective for periods ending after June 15, 2009, and shall be applied prospectively. We have included the required disclosure in Note 1 of our Notes to Condensed Consolidated Financial Statements.

Consolidation of Variable Interest Entities. In June 2009, the FASB issued Statement No. 167 (FAS167), "Amendments to FASB Interpretation No. 46(R)". FAS167 is a revision to FASB Interpretation No. 46 (Revised December 2003), "Consolidation of Variable Interest Entities", and changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The determination of whether a reporting entity is required to consolidate another entity is based on, among other things, the other entity's purpose and design and the reporting entity's ability to direct the activities of the other entity that most significantly impact the other entity's economic performance. The new standards will require a number of new disclosures. FAS167 will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. A reporting entity will be required to disclose how its involvement with a variable interest entity affects the reporting entity's financial statements. FAS167 will be effective January 1, 2010. Since we currently do not have any variable interest entities, this standard does not presently have an impact on us.

The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles. In June 2009, the FASB issued Statement No. 168 (FAS168), "FASB Accounting Standards CodificationTM (Codification)" and the Hierarchy of Generally Accepted Accounting Principles (a replacement of FAS162). FAS168 establishes the Codification as the single source of authoritative U.S. generally accepted accounting principles (U.S. GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. FAS168 and the Codification are effective for financial statements issued for interim and annual periods ending after September 15, 2009. When effective, the Codification will supersede all existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the Codification will become nonauthoritative. Following FAS168, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to: (a) update the Codification; (b) provide background information about the guidance; and (c) provide the bases for conclusions on the change(s) in the Codification. The adoption of this standard will change how we reference various elements of U.S. GAAP when preparing our financial statement disclosures, but will have no impact on our financial position, results of operation or cash flows.

NOTE 7 – STOCK-BASED COMPENSATION

We use Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment", (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) requires companies to recognize in their financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For all unvested stock options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value on the original grant date, is being recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification is recognized in the financial statements over the vesting period. The amount of our equity compensation cost relating to employees directly involved in our oil and natural gas segment is capitalized to our oil and natural gas properties. Amounts not capitalized to our oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and SARs. The value of our restricted stock grants is based on the closing stock price on the date of the grants.

For the three and six months ended June 30, 2009, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $1.8 million and $3.7 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.5 million and $1.1 million, respectively. The tax benefit related to this stock based compensation was $0.7 million and $1.4 million, respectively. For the three and six months ended June 30, 2008, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.9 million and $5.4 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.8 million and $1.6 million, respectively. The tax benefit related to this stock based compensation was $1.1 million and $2.0 million, respectively, for the three and six months of 2008. The remaining unrecognized compensation cost related to unvested awards at June 30, 2009 is approximately $9.4 million with $2.1 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.6 years.

The following table estimates the fair value of each stock option granted under all our plans during the periods reflected below using the Black-Scholes model applying the estimated values presented in the table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Options granted	3,496	28,000	3,496	28,000
Estimated fair value (in millions)	$ 0.1	$ 0.7	$ 0.1	$ 0.7
Estimate of stock volatility	0.41	0.32	0.41	0.32
Estimated dividend yield	—%	—%	—%	—%
Risk free interest rate	2%	3%	2%	3%
Expected life based on prior experience (in years)	5	5	5	5
Forfeiture rate	5%	5%	5%	5%

Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate stock option exercise and employee termination rates within the model and aggregates groups of employees that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised. The stock options granted in the second quarter of 2009 increased stock compensation expense for the second quarter and first six months of 2009 by less than $0.1 million.

The following table shows the fair value of restricted stock awards granted during the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Shares granted	—	8,750	—	23,250
Estimated fair value (in millions)	$ —	$ 0.5	$ —	$ 1.1
Percentage of shares granted Expected to be distributed	—%	89%	—%	89%

NOTE 8 – DERIVATIVES

Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, (FAS 161) became effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. FAS 161 requires enhanced disclosures about a company's derivative activities and how the related hedged items affect a company's financial position, financial performance and cash flows.

Interest Rate Swaps

From time to time we have entered into interest rate swaps to help manage our exposure to possible future interest rate increases. As of June 30, 2009, we had two outstanding interest rate swaps both of which were cash flow hedges. There was no material amount of ineffectiveness.

Term	Amount	Fixed Rate	Floating Rate
December 2007 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
December 2007 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative instruments covering a portion of our projected natural gas and oil production to reduce our exposure to market price volatility. Our decision on the quantity and price at which we choose to hedge certain of our production is based, in part, on our view of current and future market conditions. As of June 30, 2009, our derivative instruments consisted of the following types of swaps and collars:

- Swaps. We receive or pay a fixed price for the hedged commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Collars. A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

- Basis Swaps. We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the hedged commodity and pay or receive the published index price at the specified delivery point. We use basis swaps to hedge the price risk between NYMEX and its physical delivery points.

Oil and Natural Gas Segment:

At June 30, 2009, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul’09 – Dec’09	Crude oil - collar	500 Bbl/day	$100.00 put & $156.25 call	WTI – NYMEX
Jul’09 – Dec’09	Crude oil – swap	2,000 Bbl/day	$51.87	WTI – NYMEX
Jul’09 – Dec’09	Natural gas - collar	10,000 MMBtu/day	$ 8.22 put & $10.80 call	IF – NYMEX (HH)
Jul’09 – Dec’09	Natural gas – swap	30,000 MMBtu/day	$ 7.01	IF – Tenn Zone 0

Jul’09 – Dec’09	Natural gas – swap	30,000 MMBtu/day	$ 6.32	IF – CEGT
Jul’09 – Dec’09	Natural gas – swap	25,000 MMBtu/day	$ 5.57	IF – PEPL
Jan’10 – Dec’10	Crude oil - collar	500 Bbl/day	$65.00 put & $74.85 call	WTI – NYMEX
Jan’10 – Dec’10	Crude oil – swap	1,500 Bbl/day	$61.36	WTI – NYMEX
Jan’10 – Dec’10	Natural gas – swap	15,000 MMBtu/day	$ 7.20	IF – NYMEX (HH)
Jan’10 – Dec’10	Natural gas – swap	20,000 MMBtu/day	$ 6.89	IF – Tenn Zone 0
Jan’10 – Dec’10	Natural gas – swap	30,000 MMBtu/day	$ 6.12	IF – CEGT
Jan’10 – Dec’10	Natural gas – swap	20,000 MMBtu/day	$ 5.67	IF – PEPL
Jan’10 – Dec’10	Natural gas – basis differential swap	10,000 MMBtu/day	($0.79)	PEPL – NYMEX

At June 30, 2009, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jul'09 – Dec'09	Natural gas – basis differential swap	10,000 MMBtu/day	($1.02)	PEPL – NYMEX
Jul'09 – Dec'09	Natural gas – basis differential swap	10,000 MMBtu/day	($1.10)	CEGT – NYMEX

After June 30, 2009, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
Jul'09	Liquids – swap (1)	735,168 Gal/mo	$0.66	OPIS – Mont Belvieu
Jul'09	Liquids – swap (1)	555,072 Gal/mo	$0.63	OPIS – Conway
Aug'09 – Dec'09	Liquids – swap (1)	1,723,050 Gal/mo	$0.66	OPIS – Mont Belvieu
Aug'09 – Dec'09	Liquids – swap (1)	1,300,950 Gal/mo	$0.65	OPIS – Conway

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and natural butane.

The following tables present the fair values and locations of derivative instruments recorded in the balance sheet:

	Balance Sheet Location	Derivative Assets Fair Value June 30, 2009	Derivative Assets Fair Value December 31, 2008
Derivatives designated as hedging instruments		(In thousands)	
Commodity derivatives:			
Current	Current derivative assets	$ 49,166	$ 51,130
Long-term	Non-current derivative assets	7,142	5,218
Total derivatives designated as hedging instruments		56,308	56,348
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	—	1,047
Total derivatives not designated as hedging instruments		—	1,047

Total derivative assets		$ 56,308	$ 57,395

		Derivative Liabilities Fair Value	
	Balance Sheet Location	June 30, 2009	December 31, 2008
Derivatives designated as hedging instruments		(In thousands)	
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 675	$ 736
Long-term	Other long-term derivative liabilities	1,294	1,780
Commodity derivatives:			
Current	Current portion of derivative liabilities	2,756	745
Long-term	Other long-term derivative liabilities	772	—
Total derivatives designated as hedging instruments		5,497	3,261
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	1,773	—
Total derivatives not designated as hedging instruments		1,773	—
Total derivative liabilities		$ 7,270	$ 3,261

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In accordance with FASB Interpretation No. 39, “Offsetting of Amounts Related to Certain Contracts”, to the extent that a legal right of set-off exists, we net the value of our derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss) (OCI), and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of June 30, 2009 and 2008, we had a gain of $31.4 million, net of tax, and a loss of ($55.1) million, net of tax, respectively, in accumulated OCI.

Based on the market prices at June 30, 2009, we expect to transfer approximately $26.6 million, net of tax, of the gain included in the balance in accumulated OCI to earnings during the next 12 months in the related month of production. The interest rate swaps and the commodity derivative instruments as of June 30, 2009 are expected to mature by May 2012 and December 2010, respectively.

Under FAS 133, “Accounting for Derivative Instruments and Hedging Activities”, certain derivatives do not qualify for designation as cash flow hedges. Currently, we have two basis swaps that do not qualify as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur before their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in oil and natural gas revenues.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (cash flow hedges under FAS 133) for the six months ended June 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) (1)	
	2009	2008
	(In thousands)	
Interest rate swaps	$ (1,220)	$ (343)
Commodity derivatives	32,639	(54,753)
Total	$ 31,419	$ (55,096)

(1) Net of taxes.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (cash flow hedges under FAS 133) for the three months ended June 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2009	2008	2009	2008
		(In thousands)			
	Oil and natural gas revenue	$ 31,444	$ (13,418)	$ (75)	$ —

Commodity derivatives					
Commodity derivatives	Gas gathering and processing revenue	—	(1,429)	—	—
Commodity derivatives	Gas gathering and processing operating costs	—	939	—	—
Interest rate swaps	Interest, net	(249)	(106)	—	—
	Total	$ 31,195	$ (14,014)	$ (75)	$ —

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (derivatives not designated as hedging instruments under FAS 133) for the three months ended June 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2009	2008
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (1,283)	$ —
Total		$ (1,283)	$ —

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (cash flow hedges under FAS 133) for the six months ended June 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2009	2008	2009	2008
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 58,033	$ (13,530)	$ (119)	$ —
Commodity derivatives	Gas gathering and processing revenue	—	(1,548)	—	—
Commodity derivatives	Gas gathering and processing operating costs	—	1,121	—	—
Interest rate swaps	Interest, net	(437)	(55)	—	—
	Total	$ 57,596	$ (14,012)	$ (119)	$ —

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (derivatives not designated as hedging instruments under FAS 133) for the six months ended June 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2009	2008
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (2,391)	$ —
Total		$ (2,391)	$ —

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NOTE 9 – FAIR VALUE MEASUREMENTS

As of January 1, 2008, we applied the provisions of FAS 157, “Fair Value Measurements” for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of FAS 157 by one year to periods beginning after November 15, 2008 for nonfinancial assets and liabilities. As of January 1, 2009, we applied the provisions of FSP 157-2 and there was no material impact on us.

FAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1 - unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2 - significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3 - generally unobservable inputs which are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following table sets forth our recurring fair value measurements:

	June 30, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ —	$ —	$ (1,969)	$ (1,969)
Commodity derivatives	$ —	$ 1,814	$ 49,193	$51,007

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Commodity Derivatives. The fair values of our crude oil swaps are measured using estimated internal discounted cash flow calculations using NYMEX futures index.

Level 3 Fair Value Measurements

Interest Rate Swaps. The fair values of our interest rate swaps are based on estimates provided by our respective counterparties and reviewed internally using established index prices and other sources.

Commodity Derivatives. The fair values of our natural gas swaps, basis swaps and crude oil and natural gas collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the agreements.

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The following table is a reconciliation of our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended June 30, 2009		For the Six Months Ended June 30, 2009	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (2,479)	$ 109,413	$ (2,516)	$ 58,508
Total gains or losses (realized and unrealized):				
Included in earnings (loss) (1)	(249)	28,248	(437)	52,126
Included in other comprehensive income (loss)	510	(59,248)	547	(6,375)
Purchases, issuance and settlements	249	(29,220)	437	(55,066)
End of period	$ (1,969)	$ 49,193	$ (1,969)	$ 49,193
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held as of June 30, 2009	$ —	$ (972)	$ —	$ (2,940)

(1) Interest rate swaps and commodity sales swaps and collars are reported in the condensed consolidated statements of operations in interest, net and revenues, respectively.

We evaluated the non-performance risk with regard to our counterparties in our valuation at June 30, 2009 and determined it was immaterial.

NOTE 10 - INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

- Contract Drilling,
- Oil and Natural Gas and
- Mid-Stream

The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells. The oil and natural gas segment is engaged in the development, acquisition and production of oil and natural gas properties and the mid-stream segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

We evaluate the performance of each segment based on its operating income (loss), which is defined as operating revenues less operating expenses and depreciation, depletion, amortization and impairment. Our natural gas production in Canada is not significant. Certain information regarding each of our segment's operations follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands)			
Revenues:				
Contract drilling	$ 53,124	$ 167,109	$ 144,448	$ 331,023
Elimination of inter-segment revenue	3,241	15,881	5,866	32,548
Contract drilling net of inter-segment revenue	49,883	151,228	138,582	298,475
Oil and natural gas	89,601	164,299	178,505	294,301
Gas gathering and processing	30,303	73,729	60,959	130,288
Elimination of inter-segment revenue	7,070	18,929	15,583	31,265
Gas gathering and processing net of inter-segment revenue	23,233	54,800	45,376	99,023
Other	1,357	(180)	2,673	(290)
Total revenues	$ 164,074	$ 370,147	$ 365,136	$ 691,509
Operating income (loss) (1):				
Contract drilling	$ 9,843	$ 55,962	$ 35,593	$ 113,384
Oil and natural gas (2)	46,203	94,654	(208,956)	161,340
Gas gathering and processing	(76)	5,973	(2,671)	11,643
Total operating income (loss)	55,970	156,589	(176,034)	286,367
General and administrative expense	(5,493)	(6,726)	(11,582)	(13,251)
Interest expense, net	(61)	(273)	(538)	(1,093)
Other income - net	1,357	(180)	2,673	(290)
Income (loss) before income taxes	$ 51,773	$ 149,410	$ (185,481)	$ 271,733

(1) Operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, amortization and impairment and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

(2) In March 2009, we had an impairment of oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at the end of the first quarter 2009.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of June 30, 2009, and the related condensed consolidated statements of operations and comprehensive income (loss) for each of the three and six month periods ended June 30, 2009 and 2008 and the condensed consolidated statements of cash flows for the six month periods ended June 30, 2009 and 2008. These interim financial statements are the responsibility of the company's management.

We conducted our review in accordance with standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2008, and the related consolidated statements of income, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 24, 2009 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2008, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
August 4, 2009

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis (MD&A) provides an understanding of operating results and financial condition by focusing on changes in key measures from year to year. MD&A is organized in the following sections:

· General
· Business Outlook
· Executive Summary
· Financial Condition and Liquidity
· New Accounting Pronouncements
· Results of Operations

MD&A should be read in conjunction with the condensed consolidated financial statements and related notes included in this report as well as the information contained in our most recent Annual Report on Form 10-K.

Unless otherwise indicated or required by the content, when used in this report, the terms "company," "Unit," "us," "our," "we" and "its" refer to Unit Corporation and/or, as appropriate, one or more of its subsidiaries.

General

We were founded in 1963 as a contract drilling company. Today, we operate, manage and analyze our results of operations through our three principal business segments:

· Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
· Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires and produces oil and natural gas properties for our own account.
· Gas Gathering and Processing (Mid-Stream) – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our business and each of our three main operating segments depend, on a large part, on the prices we receive for our natural gas and oil production and the demand for oil and natural gas as well as for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. While our operations are located within the United States, events outside the United States can also impact us and our industry.

Recent events, both within the United States and the world, have brought about significant and immediate changes in the global financial markets which in turn are affecting the United States economy, our industry and us. In the United States, these events and others have had a significant impact on the prices for oil and natural gas as reflected in the following table:

Date	Gas Spot Price Henry Hub ($ per MMBtu)	Crude Oil WTI-Cushing, OK ($ per Bbl)
July 1, 2008	$ 13.19	$ 140.99

August 1, 2008	$	9.26	$	125.10
September 1, 2008	$	8.24	$	115.48
October 1, 2008	$	7.17	$	98.55
November 1, 2008	$	6.20	$	67.81
December 1, 2008	$	6.44	$	49.28
January 1, 2009	$	5.63	$	44.61
February 1, 2009	$	4.77	$	41.70
March 1, 2009	$	4.04	$	44.76
April 1, 2009	$	3.58	$	48.39
May 1, 2009	$	3.25	$	53.20

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June 1, 2009	$3.93	$68.58
July 1, 2009	$3.72	$69.31
August 1, 2009	$3.34	$69.45

As noted in the table above, oil and natural gas prices have declined significantly in a deteriorating national and global economic environment. The current economic environment and the decline in commodity prices are causing us (and other oil and gas companies) to reduce our overall level of drilling activity and spending. When drilling activity and spending decline for any sustained period of time our drilling rig utilization and dayrates also tend to decline as reflected in the table below:

Period	Average Rigs in Use	Average Dayrates
July 2008	108.8	$ 18,276
August 2008	111.2	$ 18,624
September 2008	112.1	$ 19,044
October 2008	111.5	$ 19,229
November 2008	97.8	$ 19,426
December 2008	81.0	$ 19,352
January 2009	63.8	$ 18,993
February 2009	52.2	$ 18,414
March 2009	42.2	$ 18,356
April 2009	37.3	$ 17,749
May 2009	30.2	$ 17,429
June 2009	27.5	$ 16,616(1)

(1) The average dayrates in June 2009 include 13 term contracts, of which one is up for renewal during the third quarter of 2009, seven are up for renewal during the fourth quarter of 2009 and the remaining five are up for renewal beyond 2009.

In addition, lower commodity prices for any sustained period of time could impact the liquidity condition of some of our industry partners and customers, which, in turn, might limit their ability to meet their financial obligations to us.

The recent slowdown in the United States and world economies has resulted (to varying degrees) in a reduction in the demand for oil and natural gas products by those industries and consumers that use those products in their business operations. The degree to which that demand is reduced and for how long it may last are unknown at this time. The recent significant reductions in demand for our commodities has resulted in lower prices for our products as well as forcing us to curtail our production of those products and has negatively impacted our drilling rig utilization which, in turn, has affected our financial results.

The impact on our business and financial results as a consequence of the recent volatility in oil and natural gas prices and the global economic crisis is uncertain in the long term, but in the short term, it has had a number of consequences for us, including the following:

- In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) as a result of a decline in commodity prices as compared to those existing at year end 2008.

- As a result of lower commodity prices combined with service costs that remain relatively high, we have reduced the number of gross wells our oil and natural gas segment plans to drill in 2009 by approximately 57% from the number of gross wells drilled in 2008. We also curtailed approximately 800 MMcf of production due to low commodity prices during the first six months of 2009.

- In late 2008, as a result of the significant decline in commodity prices and the resulting drop in demand for our drilling rigs, we stored a 1,500 horsepower diesel electric drilling rig that was scheduled to be placed into service in North Dakota during the first quarter of 2009. The mobilization has been delayed pending final negotiation with our customer. In addition, after discussions with our customers, we postponed the construction of eight additional drilling rigs we had previously anticipated building and instead substituted drilling rigs we already owned. As a result of existing contractual obligations, we expect to take delivery of a new drilling rig during the fourth quarter of 2009.

- Due to declining commodity prices of oil and natural gas, several of our drilling rig customers have significantly reduced their drilling budgets for 2009, resulting in a significant reduction in the average utilization of our drilling rig fleet. Our average utilization rate was 79% for the year ended December 31, 2008, 61% for the month of December 2008, 32% for the month of March 2009 and 21% for the month of June 2009. We currently expect this rate to continue to be depressed throughout 2009.

- We have reduced our total 2009 estimated capital expenditures for all three of our business segments by approximately 57% compared to 2008, excluding acquisitions, in order to focus keeping our capital expenditures within anticipated internally generated cash flow.

- Reduced prices for ethane resulted in curtailment of certain liquids production early in the first quarter of 2009, however with the increase in second quarter ethane prices, we did not have any curtailments of liquids production during the second quarter of 2009.

- Commitments to purchase two new processing plants were cancelled in 2009.

Executive Summary

Contract Drilling

Our second quarter 2009 utilization rate was 24%, compared to 40% and 80% in the first quarter 2009 and second quarter 2008, respectively. Dayrates for the second quarter of 2009 averaged $17,335, a decrease of 7% from the first quarter of 2009 and a decrease of 3% from the second quarter of 2008. Direct profit (contract drilling revenue less contract drilling operating expense) decreased 48% from the first quarter of 2009 and 72% from the second quarter of 2008, primarily due to the decrease in utilization. Operating cost per day decreased 2% from the first quarter of 2009 and increased 26% from the second quarter of 2008 primarily attributable to certain indirect drilling costs being spread over fewer utilization days. In the third quarter of 2008, prices for oil and natural gas started to decrease and continued to be at low levels during the second quarter of 2009 and we anticipate commodity prices will remain at depressed levels for an unknown period of time which will continue to adversely affect our dayrates and utilization.

We finished constructing one new 1,500 horsepower diesel electric drilling rig which was placed into service in the fourth quarter of 2008 in North Dakota. Mobilization has been delayed on an additional 1,500 horsepower diesel electric drilling rig to work in North Dakota that we previously announced to be placed in service during the first quarter of 2009, pending final negotiations with the customer. Regarding the plans for constructing additional drilling rigs see the above discussion in “Business Outlook”. Our anticipated 2009 capital expenditures for this segment are $77.0 million.

Oil and Natural Gas

Second quarter 2009 production from our oil and natural gas segment averaged 170,000 Mcfe per day, a 6% decrease from the average for the first quarter of 2009 and a 3% decrease from the average for the second quarter of 2008. The decreases primarily resulted from the slowdown of drilling new wells due to current economic conditions.

Oil and natural gas revenues increased 1% from the first quarter of 2009 and decreased 45% from the second quarter of 2008. Our oil, natural gas and NGL prices, including hedges, in the second quarter of 2009 increased 9%, 1% and 28%, respectively, from the first quarter of 2009 and our oil, natural gas and NGL prices, including hedges, decreased 46%, 40% and 58%, respectively, from the second quarter of 2008. Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 13% from the first quarter of 2009 and decreased 46% from the second quarter of 2008. The increase from the first quarter 2009 and the decrease from second quarter 2008 primarily resulted from the impact of commodity prices. Operating cost per Mcfe produced decreased 26% from the first quarter of 2009 and decreased 42% from the second quarter of 2008 primarily due to reduced production taxes resulting from the large decrease in commodity prices and a production tax credit received attributable to high-cost gas wells. For 2009, we have hedged approximately 65% of our average daily oil production (based on our second quarter 2009 production) and approximately 77% of our average daily natural gas production (based on our second quarter 2009 production). Currently, for 2010, we have hedged approximately 52%

of our average daily oil production (based on our second quarter 2009 production) and approximately 69% of our average daily natural gas production (based on our second quarter 2009 production).

In July 2009, we entered into two agreements to hedge approximately 55% of our average daily NGL production (based on our second quarter 2009 production) for the period July-December 2009 at an average price of $0.66 per gallon.

In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at the end of the first quarter. At June 30, 2009 commodity prices were at levels that did not require us to take a write-down of our oil and natural gas properties. However should prices, including the discounted value of our commodity hedges, after June 30, 2009 drop to levels at or below those existing at March 31, 2009 an additional write-down of the carrying value of our oil and natural gas properties could be required in future periods.

Our estimated production for 2009 is approximately 63.0 Bcfe. We currently anticipate that our oil and natural gas segment will participate in the drilling of approximately 120 wells during 2009, a decrease of 57% over 2008. Our current anticipated 2009 capital expenditures for this segment are $220.0 million.

Commodity prices which started to decrease during the third quarter of 2008, continued to be at low levels during the second quarter of 2009. We anticipate these prices will remain at current or lower levels for an indeterminable period of time. As a result of these lower commodity prices and service costs that remained relatively high, we began slowing our drilling activity during the fourth quarter of 2008 and continued to do so through the second quarter of 2009. In the Mid-Continent area, natural gas spot prices have been very weak and in certain limited circumstances we have curtailed production rather than selling the production at those prices.

Mid-Stream

Second quarter 2009 liquids sold per day increased 9% from the first quarter of 2009 and increased 18% from the second quarter of 2008. Liquids sold per day increased from the first quarter of 2009 primarily due to the processing plants operating in an ethane rejection mode due to an extremely low ethane price in the first quarter 2009, and increased from the second quarter of 2008 primarily as the result of upgrades and expansions to existing plants. Gas processed per day increased 4% over the first quarter of 2009 and increased 12% over the second quarter of 2008, respectively. Gas gathered per day decreased 2% from the first quarter of 2009 and decreased 9% from the second quarter of 2008 primarily from our Southeast Oklahoma gathering system experiencing natural production declines associated with connected wells.

NGL prices in the second quarter of 2009 increased 7% from the price received in the first quarter of 2009 and decreased 58% over the price received in the second quarter of 2008. The price of liquids as compared to natural gas affects the revenue in our mid-stream operations and determines the fractionation spread which is the difference in the value received for the NGLs recovered from natural gas in comparison to the amount received for the equivalent MMBtu’s of natural gas if unprocessed. In 2008, we had hedged approximately 50% of our average fractionation spread volumes to help manage our cash flow from this segment. We currently do not have any fractionation spread hedges in place for 2009 and beyond due to the unfavorable current market condition of futures prices.

Direct profit (mid-stream revenues less mid-stream operating expense) increased 175% from the first quarter of 2009 and decreased 58% from the second quarter of 2008. Half of the increase from the first quarter 2009 is due to the $1.3 million contract termination penalty we incurred during the first quarter of 2009 and the remainder of the increase, as well as, the decrease from the second quarter 2008 resulted primarily from changes in commodity prices which resulted in changes in processing margins. Total operating cost for our mid-stream segment decreased 7% from the first quarter of 2009 and decreased 57% from the second quarter of 2008. Our anticipated capital expenditures for

2009 for this segment are $13.0 million. Commodity prices started to decline in the third quarter of 2008 and continued to be at low levels during the second quarter of 2009 except for liquids prices which slightly increased in the second quarter of 2009. Prices may continue to decrease or remain at their current lower levels for an indeterminable period of time, which could result in fewer wells being connected to existing gathering systems and lower fractionation spreads resulting in possible future declines in volumes or margins.

Financial Condition and Liquidity

Summary. Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our Credit Facility. Our cash flow is influenced mainly by:

- the demand for and the dayrates we receive for our drilling rigs;
- the quantity of natural gas, oil and NGLs we produce;
- the prices we receive for our natural gas production and, to a lesser extent, the prices we receive for our oil and NGL production; and
- the margins we obtain from our natural gas gathering and processing contracts.

The following is a summary of certain financial information as of June 30, 2009 and 2008 and for the six months ended June 30, 2009 and 2008:

	June 30, 2009	June 30, 2008	% Change (2)
	(In thousands except percentages)		
Working capital	$ 67,036	$ 26,682	151%
Long-term debt	$ 111,000	$ 102,800	8%
Shareholders' equity (1)	$ 1,528,840	$ 1,563,706	(2)%
Ratio of long-term debt to total capitalization (1)	7%	6%	17%
Net income (loss) (1)	$ (115,462)	$ 171,192	(167)%
Net cash provided by operating activities	$ 308,842	$ 320,388	(4)%
Net cash used in investing activities	$ (181,965)	$ (302,445)	(40)%
Net cash used in financing activities	$ (126,504)	$ (18,082)	NM%

(1) In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at quarter-end. The write down impacted our 2009 shareholders' equity, ratio of long-term debt to total capitalization and net income. There was no impact on our compliance with the covenants contained in our Credit Facility.

(2) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

The following table summarizes certain operating information:

	Six Months Ended June 30, 2009	2008	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	42.1	102.5	(59)%
Total number of drilling rigs owned at the end of the period	131	131	—%
Average dayrate	$ 18,141	$ 17,943	1%
Oil and Natural Gas:			
Oil production (MBbls)	691	626	10%
Natural gas liquids production (MBbls)	784	655	20%
Natural gas production (MMcf)	22,861	23,009	(1)%
Average oil price per barrel received	$ 52.69	$ 98.08	(46)%
Average oil price per barrel received excluding hedges	$ 46.11	$ 109.42	(58)%
Average NGL price per barrel received	$ 21.29	$ 54.56	(61)%
Average NGL price per barrel received excluding hedges	$ 21.29	$ 54.43	(61)%
Average natural gas price per mcf received	$ 5.47	$ 8.43	(35)%
Average natural gas price per mcf received excluding hedges	$ 3.11	$ 8.71	(64)%
Mid-Stream:			
Gas gathered—MMBtu/day	189,980	203,047	(6)%
Gas processed—MMBtu/day	74,074	63,671	16%
Gas liquids sold — gallons/day	228,998	193,027	19%
Number of natural gas gathering systems	33	36	(8)%
Number of processing plants	8	8	—%

At June 30, 2009, we had unrestricted cash totaling $1.0 million and we had borrowed $111.0 million of the $325.0 million we had elected to have available under our Credit Facility. Our Credit Facility is used for working capital and capital expenditures. Historically, most of our capital expenditures have been discretionary and directed toward future growth. However, for 2009, in view of the current economic environment and declines in commodity prices, our focus will be aimed at keeping our capital expenditures within anticipated internally generated cash flows which will limit our ability to grow during the year.

Working Capital. Typically, our working capital balance fluctuates primarily because of the timing of our accounts receivable and accounts payable. We had working capital of $67.0 million and $26.7 million as of June 30, 2009 and 2008, respectively. The effect of our hedging activity increased working capital by $26.6 million as of June 30, 2009 and reduced working capital by $46.4 million as of June 30, 2008.

Contract Drilling. Our drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our drilling rigs and our ability to supply the equipment needed.

If the recent depressed conditions within our industry continue, we do not anticipate that competition to keep and attract qualified employees to meet our immediate future requirements will materially affect us. Likewise, if current commodity price and industry drilling utilization declines continue, we do not anticipate that our drilling labor costs will increase from those levels in effect at the end of the second quarter of 2009.

Most of our drilling rig fleet is used to drill natural gas wells so natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we charge for our contract drilling services. As natural gas prices declined late in 2008, demand for drilling rigs also declined and dayrates throughout the drilling industry started to decline. The reduction in demand for drilling rigs in the first half of 2009 was primarily the result of the uncertainty prevailing in the economy and the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2008 into 2009, due to the global economic crisis and low commodity prices. The average number of our drilling rigs used in the first six months of 2009 was 42.1 drilling rigs (32%) compared with 102.5 drilling rigs (79%) in the first six months of 2008. Based on the average utilization of our drilling rigs during the first six months of 2009, a $100 per day change in dayrates has a $4,210 per day ($1.5 million annualized) change in our pre-tax operating cash flow. For the first six months of 2009, our average dayrate was $18,141 per day compared to $17,943 per day for the first six months of 2008 as dayrates continued to increase during the second and third quarters of 2008 before the fourth quarter downturn. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas, the levels of natural gas storage and the availability of drilling rigs to meet the demands of the industry.

During the first quarter 2009, we sold one 750 horsepower drilling rig for $3.1 million and recorded a $0.9 million gain, bringing our total fleet to 131 drilling rigs.

Our contract drilling segment provides drilling services for our oil and natural gas segment. The contracts for these services contain the same terms and rates as the contracts we use with unrelated third parties for comparable type projects. During the first six months of 2009 and 2008, we drilled 13 and 65 wells, respectively, for our oil and natural gas segment. The profit our drilling segment received from drilling these wells, $1.1 million and $13.9 million, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit. The decline in our oil and natural gas segment’s drilling activity during the fourth quarter of 2008 and into 2009 has reduced the drilling services our contract drilling segment provides for our oil and natural gas segment.

Impact of Prices for Our Oil, NGLs and Natural Gas. As of December 31, 2008, natural gas comprised 79% of our oil, NGLs and natural gas reserves. Any significant change in natural gas prices has a material effect on our revenues, cash flow and the value of our oil, NGLs and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, economic conditions, supply imbalances and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first six months of 2009 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $371,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production during the first six months of 2009 was $5.47 compared to $8.43 for the first six months of 2008. Based on our first six months of 2009 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $109,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $124,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow based on our production in the first six months of 2009. In the first six months of 2009, our average oil price per barrel received was $52.69 compared with an average oil price of $98.08 in the first six months of 2008 and our first six months of 2009 average NGLs price per barrel received was $21.29 compared with an average NGL price per barrel of $54.56 in the first six months of 2008.

Because natural gas prices have such a significant effect on the value of our oil, NGLs and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at quarter-end. At June 30, 2009 commodity prices were at levels that did not require us to take a write-down of our oil and natural gas properties. However should prices, including the discounted value of our commodity hedges, after June 30, 2009 drop to levels at or below those existing at March 31, 2009 an additional write-down of the carrying value of our oil and natural gas properties could be required in future periods. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our bank credit facility since that determination is based mainly on the value of our oil, NGLs and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

Since oil and natural gas prices can be volatile, we may be required to write down the carrying value of our oil and natural gas properties at the end of future reporting periods. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

We sell most of our natural gas production to third parties under month-to-month contracts.

Mid-Stream Operations. Our mid-stream operations are engaged primarily in the buying and selling, gathering, processing and treating of natural gas. This segment operates three natural gas treatment plants, eight processing plants, 33 gathering systems and 828 miles of pipeline. In addition, this segment enhances our ability to gather and market not only our own natural gas production but also that owned by third parties as well as providing us with additional opportunities to construct or acquire existing natural gas gathering and processing facilities. During the first six months of 2009 and 2008, our mid-stream operations purchased $13.0 million and $29.1 million, respectively, of our oil and natural gas segment's production and provided gathering and transportation services to it of $2.6 million and $2.2 million, respectively. The decrease in the production purchased from our oil and natural gas segment was primarily due to the decline in natural gas prices. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas exploration segment has been eliminated in our consolidated condensed financial statements.

Gas gathering volumes in the first six months of 2009 were 189,980 MMBtu per day compared to 203,047 MMBtu per day in the first six months of 2008, processed volumes were 74,074 MMBtu per day in the first six months of 2009 compared to 63,671 MMBtu per day in the first six months of 2008 and the amount of NGLs sold were 228,998 gallons per day in the first six months of 2009 compared to 193,027 gallons per day in the first six months of 2008. Gas gathering volumes per day in 2009 decreased 6% compared to 2008 primarily due to a volumetric decline in our Southeast Oklahoma gathering system due to natural production declines associated with the connected wells partially offset by the shutdown for approximately 10 days during February 2008 of a third-party processing plant on a different system. Processed volumes increased 16% over the comparative six months and NGLs sold also increased 19% over the comparative period primarily due to the addition of wells connected in 2008 and the first six months of 2009 and recent upgrades to several of our processing systems.

Our Credit Facility. On December 23, 2008, we entered into a First Amendment to our existing First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of $400.0 million maturing on May 24, 2012. This amendment increased the lenders' commitment by $50.0 million to an aggregate of $325.0 million. Borrowings under the Credit Facility are limited to a commitment amount elected by us. As of June 30, 2009, the commitment amount was $325.0 million. We are charged a commitment fee of 0.375 to 0.50 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility and $478,125 associated with the December 23, 2008 First Amendment. These fees are being amortized over the life of the agreement. The average interest rate for the first six months of 2009, which includes the effect of our interest rate swaps, was 3.8% compared to 5.0% for the first six months of 2008. At June 30, 2009 and July 31, 2009, borrowings were $111.0 million and $80.0 million, respectively.

The lenders under our Credit Facility and their respective participation interests are as follows:

Lender	Participation Interest
Bank of Oklahoma, N.A.	18.75%
Bank of America, N.A.	18.75%
BMO Capital Markets Financing, Inc.	18.75%
Compass Bank	17.50%
Comerica Bank	08.75%

Fortis Capital Corp.	08.75%
Calyon New York Branch	08.75%
	100.00%

The lenders' aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil, NGLs and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The current borrowing base is $475.0

31

million per the April 1, 2009 redetermination. We or the lenders may request a onetime special redetermination of the borrowing base amount between each scheduled redetermination. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid on three days prior notice to the administrative agent and on our payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under the LIBOR bear interest at the BOKF National Prime Rate, which in no event will be less than LIBOR plus 1.00%, payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without premium or penalty. At June 30, 2009, $108.5 million of our then outstanding borrowings of $111.0 million were subject to LIBOR.

The Credit Facility prohibits:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain very limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The Credit Facility also requires that we have at the end of each quarter:

- a consolidated net worth of at least $900.0 million;
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

As of June 30, 2009, we were in compliance with all the covenants contained in the Credit Facility.

We entered into the following interest rate swaps to help manage our exposure to possible future interest rate increases:

Term	Amount	Fixed Rate	Floating Rate
December 2007 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
December 2007 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Capital Requirements

Contract Drilling Acquisitions and Capital Expenditures. Due to the downturn in the oil and natural gas industry, construction of new drilling rigs has been reduced in 2009 when compared with 2008. We currently do not have a shortage of drill pipe and drilling equipment so our anticipated capital expenditures for 2009 are $77.0 million or 61% less than actual capital expenditures in 2008. At June 30, 2009, we had commitments to purchase approximately $10.3 million of drilling rig components and $16.5 million of drill pipe and drill collars in 2009. We also had committed to purchase $14.8 million of drill pipe and drill collars in the first six months of 2010. We have spent $30.7 million in capital expenditures as of June 30, 2009.

For 2008, our capital expenditures were $196.2 million. During the second quarter of 2008, we completed the construction of two new 1,500 horsepower diesel electric drilling rigs for approximately $32.2 million and placed these drilling rigs into service in our Rocky Mountain division. During the fourth quarter of 2008, we completed the construction of another new 1,500 horsepower diesel electric drilling rig for approximately $14.1 million and placed that drilling rig into service in North Dakota.

In late 2008, as a result of the significant decline in commodity prices and the resulting drop in demand for our drilling rigs, we stored a 1,500 horsepower diesel electric drilling rig in our Oklahoma City rig fabrication facility and yard that was scheduled to be placed into service in North Dakota during the first quarter of 2009. The mobilization has been delayed pending final negotiation with our customer. In addition, after discussions with our customers, we postponed the construction of eight additional drilling rigs we had previously anticipated building and instead substituted drilling rigs we already owned. As a result of existing contractual obligations, we expect to take delivery of a new drilling rig during the fourth quarter of 2009.

Oil and Natural Gas Segment Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil, NGLs and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 37 gross wells (12.72 net wells) in the first six months of 2009 compared to 129 gross wells (61.54 net wells) in the first six months of 2008. Total capital expenditures for the first six months of 2009 by this segment, excluding a $0.1 million plugging liability, totaled $110.5 million. Currently we plan to participate in drilling an estimated 120 gross wells in 2009 and estimate our total capital expenditures for our oil and natural gas segment will be approximately $220.0 million. Whether we drill the full number of wells we are planning on drilling is dependent on a number of factors (many of which are beyond our control) including the prices for oil, NGLs and natural gas, demand for oil and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners.

On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells. The purchase price was $16.8 million which consisted of $15.8 million allocated to the reserves of the wells and $1.0 million allocated to the undeveloped leasehold.

In September 2008, we completed an acquisition consisting of a 75% working interest in four producing wells and other proved undeveloped properties for $22.2 million along with working interests in undeveloped leasehold valued at approximately $3.5 million, all located in the Texas Panhandle region.

During 2008, we acquired interests in approximately 58,089 net undeveloped acres in the Marcellus Shale, located mainly in Pennsylvania. As of July 14, 2009, of that acreage approximately 9,000 net acres are subject to an agreement between us and certain unaffiliated third parties under which those parties have until September 30, 2009 to pay us approximately $40 million representing payment for our 50% interest in that acreage as well as reimbursing for us for their 50% share of the costs we paid to acquire the acreage. If payment is not timely made, then those parties will no longer have any rights in and to the 9,000 acres.

Mid-Stream Acquisitions and Capital Expenditures. During the first six months of 2009, our mid-stream segment incurred $5.9 million in capital expenditures as compared to $16.2 million in the first six months of 2008. For 2009, we have budgeted capital expenditures of approximately $13.0 million.

As of December 31, 2008, we had commitments to purchase two new processing plants. After December 31, 2008, we cancelled the purchase of one of these plants due to nonperformance of contractual terms. We are seeking to recover the $2.8 million progress payments made toward the full purchase price before this contract was terminated. In March

2009, we cancelled our remaining commitment for the second plant and incurred a $1.3 million penalty.

Contractual Commitments. At June 30, 2009, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Bank debt (1)	$ 118,809	$ 3,259	$ 115,550	$ —	$ —
Operating leases (2)	1,770	1,301	469	—	—
Drill pipe, drilling components and equipment purchases (3)	41,601	41,601	—	—	—
Total contractual obligations	$ 162,180	$ 46,161	$ 116,019	$ —	$ —

(1) See previous discussion in MD&A regarding our Credit Facility. This obligation is presented in accordance with the terms of the Credit Facility and includes interest calculated using our June 30, 2009 interest rate of 2.9% which includes the effect of the interest rate swaps.

(2) We lease office space or yards in Tulsa, Oklahoma; Canadian and Houston, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2012. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) For the next twelve months, we have committed to purchase approximately $41.6 million of new drilling rig components, drill pipe, drill collars and related equipment.

At June 30, 2009, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Deferred compensation plan (1)	$ 1,749	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 5,520	$ 1,505	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$ 5,301	$ 4,529	$ 772	$ —	$ —
Derivative liabilities – interest rate swaps	$ 1,969	$ 675	$ 1,294	$ —	$ —
Plugging liability (3)	$ 50,586	$ 968	$ 12,192	$ 3,014	$ 34,412
Gas balancing liability (4)	$ 3,364	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$ 24,560	$ 8,167	$ 3,475	$ 1,184	$ 11,734

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Condensed Consolidated Balance Sheet, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended. At June 30, 2009, there were 31 eligible employees to participate in the Special Plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143 (FAS 143), "Accounting for Asset Retirement Obligations," we have recorded the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2008, with a subsidiary of ours serving as general partner. The Partnerships were formed for the

purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $1,000 in 2009, $241,000 in 2008 and did not have any repurchases in 2007.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

Derivative Activities. As of January 1, 2009, we applied the provisions of Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, (FAS 161) which became effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. FAS 161 requires enhanced disclosures about a company's derivative activities and how the related hedged items affect a company's financial position, financial performance and cash flows. These enhanced disclosures are discussed in Note 8 of our Notes to Condensed Consolidated Financial Statements.

Periodically we enter into hedge transactions covering part of the interest we incur under our Credit Facility as well as the prices to be received for a portion of our future oil, NGLs and natural gas production.

Interest Rate Swaps. From time to time we have entered into interest rate swaps to help manage our exposure to possible future interest rate increases under our Credit Facility. As of June 30, 2009, we had two outstanding interest rate swaps which were cash flow hedges. There was no material amount of ineffectiveness. Our June 30, 2009 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
	($ in thousands)			
December 2007 – May 2012	$ 15,000	4.53%	3 month LIBOR	$ (1,064)
December 2007 – May 2012	$ 15,000	4.16%	3 month LIBOR	(905)
				$ (1,969)

Because of these interest rate swaps, interest expense increased by $0.2 million and $0.4 million for the three and six months ended June 30, 2009, respectively. A loss of $1.2 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of June 30, 2009. Interest expense increased by $0.1 million for both the three and six months ended June 30, 2008.

Commodity Hedges. We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our production is based, in part, on our view of current and future market conditions. Based on our second quarter 2009 average daily production, as of June 30, 2009, the approximated percentages we have hedged are as follows:

Oil and Natural Gas Segment:

	July – December 2009	January – December 2010
Daily oil production	65%	52%
Daily natural gas production	77%	69%

With respect to the commodities subject to the hedge, the use of hedging limits the risk of adverse downward price movements, however it also limits increases in future revenues that would otherwise result from favorable price movements.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties in our valuation at June 30, 2009 and determined it was immaterial at that time. At June 30, 2009, Bank of Montreal, Bank of Oklahoma, N.A., Bank of America, N.A., Calyon New York Branch, Comerica Bank and Compass Bank were the counterparties with respect to all of our commodity derivative transactions. At June 30, 2009, the fair values of the net assets (liabilities) we had with each of these counterparties was $19.2 million, $7.5 million, $23.3 million, $4.0 million, $0.5 million and ($3.5) million, respectively.

In accordance with FASB Interpretation No. 39, to the extent that a legal right of set-off exists, we net the value of our derivative arrangements with the same counterparty in the accompanying consolidated balance sheets. At June 30, 2009, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $49.2 million and $7.1 million, respectively, and current and non-current derivative liabilities of $4.5 million and $0.8. At June 30, 2008, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of $73.5 million and $13.6 million, respectively.

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of June 30, 2009, we had a gain of $32.6 million, net of tax from our oil and natural gas segment derivatives and no gain or loss from our mid-stream segment derivatives in accumulated other comprehensive income (loss).

Based on market prices at June 30, 2009, we expect to transfer approximately $26.6 million, net of tax, of the gain included in the balance in accumulated other comprehensive income (loss) to earnings during the next 12 months in the related month of production. All derivative instruments as of June 30, 2009 are expected to mature by December 31, 2010.

Under FAS 133, certain derivatives do not qualify for designation as cash flow hedges. Currently, we have two basis swaps that do not qualify as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur before their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income (loss) until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas revenues as unrealized gains (losses). The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at June 30:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands)			
Increases (decreases) in:				
Oil and natural gas revenue:				
Realized gains (losses) on oil and natural gas derivatives	$ 31,058	$ (13,418)	$ 58,463	$ (13,530)
Unrealized losses on ineffectiveness of cash flow hedges	(75)	—	(119)	—
Unrealized losses on non-qualifying oil and natural gas derivatives	(897)	—	(2,821)	—
Total increase on oil and natural gas revenues due to derivatives	30,086	(13,418)	55,523	(13,530)
Gas gathering and processing revenue (all realized gains (losses))	—	(1,429)	—	(1,548)
Gas gathering and processing operating costs (all realized (gains) losses)	—	(939)	—	(1,121)

Impact on pre-tax earnings	$	30,086	$	(13,908	)	$	55,523	$	(13,957)

Stock and Incentive Compensation. During the first six months of 2009, we did not grant any awards of restricted stock. During the first six months of 2009, we recognized compensation expense of $3.7 million for all of our restricted stock, stock options and SAR grants and capitalized $1.1 million of compensation cost for oil and natural gas properties.

Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $5,000 for motor truck cargo liability to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner of 14 oil and natural gas partnerships which were formed privately or publicly. Each partnership’s revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party’s share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party’s behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party’s level of activity and are considered by us to be reasonable. For the first six months of 2009 and 2008, the total we received for all of these fees was $0.7 million and $0.9 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our condensed consolidated financial statements.

New Accounting Pronouncements

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied on to prepare reserves estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based on the first-of-month posted price for each month in the prior twelve-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our consolidated financial statements.

Interim Disclosures about Fair Value of Financial Instruments. In April 2009, the Financial and Accounting Standards Board (FASB) issued FASB Staff Position (FSP) Statement No. 107-1 and Accounting Principles Board (APB) 28-1 (collectively, FSP FAS 107-1), “Interim Disclosures about Fair Value of Financial Instruments.” FSP FAS 107-1 amends FAS 107, “Disclosures about Fair Value of Financial Instruments,” to require an entity to provide disclosures about fair value of financial instruments in interim financial information. The FSP FAS 107-1 also amends APB Opinion 28, “Interim Financial Reporting,” to require those disclosures in summarized financial information at interim reporting periods. Under FSP FAS 107-1, we will be required to include disclosures about the fair value of our financial instruments whenever we issue financial information for interim reporting periods. In addition, we will be required to disclose in the body or in the accompanying notes of our summarized financial information for interim reporting periods and in our financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 is effective for periods ending after June 15, 2009. We have included the required disclosure in Note 4 of our Notes to Condensed Consolidated Financial Statements.

Subsequent Events. In May 2009, the FASB issued FASB Statement No. 165 (FAS165), “Subsequent Events”. FAS165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. FAS165 provides:

- The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;
- The circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and
- The disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

FAS165 is effective for periods ending after June 15, 2009, and shall be applied prospectively. We have included the required disclosure in Note 1 of our Notes to Condensed Consolidated Financial Statements.

Consolidation of Variable Interest Entities. In June 2009, the FASB issued Statement No. 167 (FAS167), “Amendments to FASB Interpretation No. 46(R)”. FAS167 is a revision to FASB Interpretation No. 46 (Revised December 2003), “Consolidation of Variable Interest Entities”, and changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The determination of whether a reporting entity is required to consolidate another entity is based on, among other things, the other entity’s purpose and design and the reporting entity’s ability to direct the activities of the other entity that most significantly impact the other entity’s economic performance. The new standards will require a number of new disclosures. FAS167 will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. A reporting entity will be required to disclose how its involvement with a variable interest entity affects the reporting entity’s financial statements. FAS167 will be effective January 1, 2010, since we currently do not have any variable interest entities, this standard does not presently have an impact on us.

The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles. In June 2009, the FASB issued Statement No. 168 (FAS168), “FASB Accounting Standards CodificationTM (Codification)” and the Hierarchy of Generally Accepted Accounting Principles (a replacement of FAS162). FAS168 establishes the Codification as the single source of authoritative U.S. generally accepted accounting principles (U.S. GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. FAS168 and the Codification are effective for financial statements issued for interim and annual periods ending after September 15, 2009. When effective, the Codification will supersede all existing non-SEC accounting and reporting standards. All other nongrandfathered non-SEC accounting literature not included in the Codification will become nonauthoritative. Following FAS168, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to: (a) update the Codification; (b) provide background information about the guidance; and (c) provide the bases for conclusions on the change(s) in the Codification. The adoption of this standard will change how we reference various elements of U.S. GAAP when preparing our financial statement disclosures, but will have no impact on our financial position, results of operation or cash flows.

Results of Operations

Quarter Ended June 30, 2009 versus Quarter Ended June 30, 2008

Provided below is a comparison of selected operating and financial data:

	Quarter Ended June 30, 2009	2008	Percent Change
Total revenue	$ 164,074,000	$ 370,147,000	(56)%
Net income	$ 32,031,000	$ 94,128,000	(66)%
Contract Drilling:			
Revenue	$ 49,883,000	$ 151,228,000	(67)%
Operating costs excluding depreciation	$ 29,779,000	$ 78,278,000	(62)%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	31.6	104.5	(70)%
Average dayrate on daywork contracts	$ 17,335	$ 17,890	(3)%
Depreciation	$ 10,261,000	$ 16,988,000	(40)%
Oil and Natural Gas:			
Revenue	$ 89,601,000	$ 164,299,000	(45)%
Operating costs excluding depreciation, depletion and amortization	$ 17,249,000	$ 30,657,000	(44)%
Average oil price (Bbl)	$ 54.84	$ 102.23	(46)%
Average NGL price (Bbl)	$ 23.88	$ 56.78	(58)%
Average natural gas price (Mcf)	$ 5.49	$ 9.16	(40)%
Oil production (Bbl)	348,000	335,000	4%
NGL production (Bbl)	391,000	350,000	12%
Natural gas production (Mcf)	10,999,000	11,848,000	(7)%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.68	$ 2.43	(31)%
Depreciation, depletion and amortization	$ 26,149,000	$ 38,988,000	(33)%
Mid-Stream Operations:			
Revenue	$ 23,233,000	$ 54,800,000	(58)%
Operating costs excluding depreciation and amortization	$ 19,199,000	$ 45,164,000	(57)%
Depreciation and amortization	$ 4,110,000	$ 3,663,000	12%
Gas gathered—MMBtu/day	187,666	205,397	(9)%
Gas processed—MMBtu/day	75,481	67,545	12%
Gas liquids sold—gallons/day	239,121	202,130	18%
General and administrative expense	$ 5,493,000	$ 6,726,000	(18)%
Interest expense, net	$ 61,000	$ 273,000	(78)%
Income tax expense	$ 19,742,000	$ 55,282,000	(64)%
Average interest rate	3.6%	4.4%	(18)%
Average long-term debt outstanding	$ 140,678,000	$ 114,423,000	23%

Contract Drilling:

Drilling revenues decreased $101.3 million or 67% in the second quarter of 2009 versus the second quarter of 2008 primarily due to a 70% decrease in the average number of rigs in use during the second quarter of 2009 compared to the second quarter of 2008. Average drilling rig utilization decreased from 104.5 drilling rigs in the second quarter of 2008 to 31.6 drilling rigs in the second quarter of 2009. Our average dayrate in the second quarter of 2009 was 3% lower than in the second quarter of 2008. In the third quarter of 2008, prices for oil and natural gas started to decrease and have continued to be at low levels during the second quarter of 2009 and may continue to do so for an unknown period of time. Entering the third quarter of 2009, the decline in utilization has started to moderate, but the reduction in commodity prices has continued to reduce the demand for drilling rigs which may bring utilization rates even lower. This reduction in commodity prices will further reduce our utilization dayrates from average second quarter 2009 levels.

Drilling operating costs decreased $48.5 million or 62% between the comparative second quarters of 2009 and 2008 primarily due to the decrease in the number of drilling rigs used. The industry utilization decreases since the third quarter of 2008, has reduced the demand for personnel which in turn has reduced the pressure on our labor costs. Likewise, we anticipate that pressure on other daily direct drilling costs should result in a decrease of those costs as well, but reduced utilization will result in fewer rigs to cover our indirect fixed costs. Contract drilling depreciation decreased $6.7 million or 40% primarily due to a decrease in rig utilization.

Oil and Natural Gas:

Oil and natural gas revenues decreased $74.7 million or 45% in the second quarter of 2009 as compared to the second quarter of 2008 primarily due to a decrease in average oil, NGL and natural gas prices and by a 3% decrease in equivalent production volumes. Average oil prices between the comparative quarters decreased 46% to $54.84 per barrel, NGL prices decreased 58% to $23.88 per barrel and natural gas prices decreased 40% to $5.49 per Mcf. In the second quarter of 2009, as compared to the second quarter of 2008, oil production increased 4%, NGL production increased 12% and natural gas production decreased 7%. During the second quarter of 2009 we curtailed approximately 440 MMcf of natural gas production due to low commodity prices. A large part of our increase in revenues during 2008 was determined by the prices we received for our production. Commodity prices started to decrease during the third quarter of 2008 and continued to be at low levels during the second quarter of 2009 and may continue to decrease or remain at their current levels for an indeterminable period of time. As a result of lower commodity prices combined with service costs that remained relatively high, we began slowing down our drilling activity during the fourth quarter of 2008 through the second quarter of 2009 and plan to increase activity during the second half of 2009.

Oil and natural gas operating costs decreased $13.4 million or 44% between the comparative second quarters of 2009 and 2008 primarily due to reduced production taxes resulting from the large decrease in commodity prices and a $5.8 million production tax credit received attributable to high-cost gas wells. Lease operating expenses per Mcfe increased 14% to $1.09 and partially offset the decrease in production taxes. General and administrative expenses decreased as compensation costs were reduced in response to the downturn in the industry while lease operating expenses increased slightly primarily due to an increase in the number of wells producing and also from increases in the cost of goods purchased and third-party services.

Depreciation, depletion and amortization (“DD&A”) decreased $12.8 million or 33% primarily due to a 31% decrease in our DD&A rate. The decrease in our DD&A rate in the second quarter of 2009 compared to the second quarter of 2008 resulted primarily from the $282.0 million and $281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties in the fourth quarter of 2008 and the first quarter 2009, respectively, as a result of a decline in commodity prices. At June 30, 2009 commodity prices were at levels that did not require us to take a write-down of our oil and natural gas properties. However should prices, including the discounted value of our commodity hedges, after June 30, 2009 drop to levels at or below those existing at March 31, 2009 an additional write-down of the carrying value of our oil and natural gas properties could be required in future periods.

Prior to the third quarter of 2008, the increase in commodity prices over the previous year increased the cost of acquiring producing properties. However, recent decreases in commodity prices, combined with nation-wide concerns regarding credit availability may lead to less competition for producing property acquisitions.

Mid-Stream:

Our mid-stream revenues were $31.6 million or 58% lower for the second quarter of 2009 as compared to the second quarter of 2008 primarily due to lower NGL and natural gas prices slightly offset by higher NGL volumes processed and sold. The average price for NGLs sold decreased 58% and the average price for natural gas sold decreased 71%. Gas processing volumes per day increased 12% between the comparative quarters and NGLs sold per day increased 18% between the comparative quarters. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems throughout 2008. NGLs sold

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volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes per day decreased 9% primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma. NGL sales were reduced by $1.4 million in the second quarter of 2008 due to the impact of NGL hedges. There were no NGL hedges in place for the second quarter of 2009.

Operating costs decreased $26.0 million or 57% in the second quarter of 2009 compared to the second quarter of 2008 primarily due to a 68% decrease in prices paid for natural gas purchased and a 3% decrease in field operating expense in the second quarter of 2009 due to consolidations of our natural gas gathering and processing systems, slightly offset by a 9% increase in natural gas volumes purchased per day and a 6% increase in general and administrative expenses associated with our mid-stream segment. The total number of employees working in our mid-stream segment increased by 8% over the comparative quarters. Depreciation and amortization increased $0.4 million, or 12%, primarily attributable to the additional depreciation associated with capital expenditures between the comparative periods. Operating costs were reduced by $0.9 million in the second quarter of 2008 due to the impact of natural gas purchase hedges; however there were no hedges in place during the second quarter of 2009. Should the ongoing decline in commodity prices cause a reduction in the wells drilled by non-affiliated companies, our ability to connect additional wells to our existing gathering systems would be reduced resulting in possible future declines in our volumes or margins.

Other:

General and administrative expense decreased $1.2 million or 18% in the second quarter of 2009 compared to the second quarter of 2008. This decrease was primarily attributable to decreased payroll expenses due to efforts to manage cost in this economic environment.

Interest expense, net of capitalized interest, decreased $0.2 million or 78% between the comparative quarters. Capitalized interest reduced our interest expense by $1.5 million in the second quarter of 2009 versus $1.2 million in the second quarter of 2008. We capitalized interest based on the net book value associated with our undeveloped oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate was 18% lower while our average debt outstanding was 23% higher in the second quarter of 2009 as compared to the second quarter of 2008. Interest expense was increased $0.2 million for the second quarter of 2009 and $0.1 million for the second quarter of 2008 from interest rate swap settlements.

Income tax expense decreased by $35.5 million or 64% in the second quarter of 2009 compared to the second quarter of 2008 due to reduced income from lower commodity prices and rig utilization. Our effective tax rate for the second quarter of 2009 was 38.1% versus 37.0% for the second quarter of 2008. The portion of our taxes reflected as current income tax expense for the second quarter of 2009 was $1.2 million or 6% of total income tax expense in the second quarter of 2009 as compared with $9.7 million or 18% of total income tax expense in the second quarter of 2008. The reduction in the percentage of tax expense recognized as current is the result of less taxable income projected for 2009. Income taxes paid in the second quarter of 2009 were $1.8 million.

Six Months Ended June 30, 2009 versus Six Months Ended June 30, 2008

Provided below is a comparison of selected operating and financial data:

	Six Months Ended June 30, 2009	2008	Percent (1) Change
Total revenue	$ 365,136,000	$ 691,509,000	(47)%
Net income (loss)	$ (115,462,000)	$ 171,192,000	(167)%
Contract Drilling:			
Revenue	$ 138,582,000	$ 298,475,000	(54)%
Operating costs excluding depreciation	$ 80,109,000	$ 152,739,000	(48)%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	42.1	102.5	(59)%
Average dayrate on daywork contracts	$ 18,141	$ 17,943	1%
Depreciation	$ 22,880,000	$ 32,352,000	(29)%
Oil and Natural Gas:			
Revenue	$ 178,505,000	$ 294,301,000	(39)%
Operating costs excluding depreciation, depletion, amortization and impairment	$ 42,065,000	$ 58,258,000	(28)%
Average oil price (Bbl)	$ 52.69	$ 98.08	(46)%
Average NGL price (Bbl)	$ 21.29	$ 54.56	(61)%
Average natural gas price (Mcf)	$ 5.47	$ 8.43	(35)%
Oil production (Bbl)	691,000	626,000	10%
NGL production (Bbl)	784,000	655,000	20%
Natural gas production (Mcf)	22,861,000	23,009,000	(1)%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.01	$ 2.42	(17)%
Depreciation, depletion and amortization	$ 64,155,000	$ 74,703,000	(14)%
Impairment of oil and natural gas properties	$ 281,241,000	$ —	NM%
Mid-Stream Operations:			
Revenue	$ 45,376,000	$ 99,023,000	(54)%
Operating costs excluding depreciation and amortization	$ 39,876,000	$ 80,236,000	(50)%
Depreciation and amortization	$ 8,171,000	$ 7,144,000	14%
Gas gathered—MMBtu/day	189,980	203,047	(6)%
Gas processed—MMBtu/day	74,074	63,671	16%
Gas liquids sold—gallons/day	228,998	193,027	19%
General and administrative expense	$ 11,582,000	$ 13,251,000	(13)%
Interest expense	$ 538,000	$ 1,093,000	(51)%
Income tax expense (benefit)	$ (70,019,000)	$ 100,541,000	(170)%
Average interest rate	3.8%	5.0%	(24)%
Average long-term debt outstanding	$ 168,074,000	$ 126,209,000	33%

(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

Contract Drilling:

Drilling revenues decreased $159.9 million or 54% in the first six months of 2009 versus the first six months of 2008 primarily due to a 59% decrease in the average number of rigs in use during the first six months of 2009 compared to the first six months of 2008. Average drilling rig utilization decreased from 102.5 drilling rigs in the first six months of 2008 to 42.1 drilling rigs in the first six months of 2009. Our average dayrate in the first six months of 2009 was 1% higher than in the first six months of 2008. In the third quarter of 2008, prices for oil and natural gas started to decrease and have continued to be at low levels during the first six months of 2009 and may continue to do so for an unknown period of time. Entering the third quarter of 2009, the decline in utilization has started to moderate, but the reduction in commodity prices has continued to reduce the demand for drilling rigs which may bring utilization rates even lower. This reduction in commodity prices will further reduce our utilization dayrates from average first six months of 2009 levels.

Drilling operating costs decreased $72.6 million or 48% between the comparative first six months of 2009 and 2008 primarily due to the decrease in the number of drilling rigs used. The recent industry utilization decreases since the third quarter of 2008, has reduced the demand for personnel which in turn has reduced the pressure on our labor costs. Likewise, we anticipate that pressure on other daily direct drilling costs should result in a decrease of those costs as well, but reduced utilization will result in fewer rigs to cover our indirect fixed costs. Contract drilling depreciation decreased $9.5 million or 29% primarily due to a decrease in rig utilization.

Oil and Natural Gas:

Oil and natural gas revenues decreased $115.8 million or 39% in the first six months of 2009 as compared to the first six months of 2008 primarily due to a decrease in average oil, NGL and natural gas prices somewhat offset by a 3% increase in equivalent production volumes. Average oil prices between the comparative years decreased 46% to $52.69 per barrel, NGL prices decreased 61% to $21.29 per barrel and natural gas prices decreased 35% to $5.47 per Mcf. In the first six months of 2009, as compared to the first six months of 2008, oil production increased 10%, NGL production increased 20% and natural gas production decreased 1%. During the first six months of 2009 we curtailed approximately 800 MMcf of natural gas production due to low commodity prices. A large part of our increase in revenues during 2008 was determined by the prices we received for our production. Commodity prices started to decrease during the third quarter of 2008 and continued to be at low levels during the first six months of 2009 and may continue to decrease or remain at their current levels for an indeterminable period of time. As a result of lower commodity prices combined with service costs that remained relatively high, we began slowing down our drilling activity during the fourth quarter of 2008 through the second quarter of 2009 and plan to increase activity during the second half of 2009.

Oil and natural gas operating costs decreased $16.2 million or 28% between the comparative first six months of 2009 and 2008 primarily due to reduced production taxes resulting from the large decrease in commodity prices and a $5.8 million production tax credit received attributable to high-cost gas wells. Lease operating expenses per Mcfe increased 10% to $1.08 and partially offset the decrease in production taxes. General and administrative expenses decreased as compensation costs were reduced in response to the downturn in the industry while lease operating expenses increased slightly primarily due to an increase in the number of wells producing and also from increases in the cost of goods purchased and third-party services.

DD&A decreased $10.5 million or 14% primarily due to a 17% decrease in our DD&A rate slightly offset by higher production volumes. The decrease in our DD&A rate in the first six months of 2009 compared to the first six months of 2008 resulted primarily from the $282.0 million and $281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties in the fourth quarter of 2008 and the first quarter 2009, respectively, as a result of a decline in commodity prices. At June 30, 2009 commodity prices were at levels that did not require us to take a write-down of our oil and natural gas properties. However should prices, including the discounted value of our commodity hedges, after June 30, 2009 drop to levels at or below those existing at March 31, 2009 an additional write-down of the carrying value of our oil and natural gas properties could be required in future periods.

Prior to the third quarter of 2008, the increase in commodity prices over the previous year increased the cost of acquiring producing properties. However, recent decreases in commodity prices, combined with nation-wide concerns regarding credit availability may lead to less competition for producing property acquisitions.

Mid-Stream:

Our mid-stream revenues were $53.6 million or 54% lower for the first six months of 2009 as compared to the first six months of 2008 primarily due to lower NGL and natural gas prices slightly offset by higher NGL volumes processed and sold. The average price for NGLs sold decreased 58% and the average price for natural gas sold decreased 65%. Gas processing volumes per day increased 16% between the comparative six month periods and NGLs sold per day increased 19% between the comparative six month periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems throughout 2008. NGLs sold volumes per day increased due to upgrades to several of our processing facilities. Gas gathering volumes per day decreased 6% primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma. NGL sales were reduced by $1.5 million in the first six months of 2008 due to the impact of NGL hedges. There were no NGL hedges in place for the first six months of 2009.

Operating costs decreased $40.4 million or 50% in the first six months of 2009 compared to the first six months of 2008 primarily due to a 63% decrease in prices paid for natural gas purchased, slightly offset by a 13% increase in natural gas volumes purchased per day, a 2% increase in field operating expense due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and a 10% increase in general and administrative expenses associated with our mid-stream segment. The total number of employees working in our mid-stream segment increased by 23% over the comparative six month periods. Depreciation and amortization increased $1.0 million, or 14%, primarily attributable to the additional depreciation associated with capital expenditures between the comparative six month periods. Operating costs were reduced by $1.1 million in the first six months of 2008 due to the impact of natural gas purchase hedges; however there were no hedges in place during the first six months of 2009. Should the recent decline in commodity prices cause a reduction in the wells drilled by non-affiliated companies, our ability to connect additional wells to our existing gathering systems would be reduced resulting in possible future declines in our volumes or margins.

Other:

General and administrative expense decreased $1.7 million or 13% in the first six months of 2009 compared to the first six months of 2008. This decrease was primarily attributable to decreased payroll expenses due to efforts to manage cost in this economic environment.

Interest expense, net of capitalized interest, decreased $0.6 million or 51% between the comparative six month periods of 2009 and 2008. Capitalized interest reduced our interest expense by $3.2 million in the first six months of 2009 versus $2.3 million in the first six months of 2008. We capitalized interest based on the net book value associated with our undeveloped oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate was 24% lower and our average debt outstanding was 33% higher in the first six months of 2009 as compared to the first six months of 2008. Interest expense was increased $0.4 million for the first six months of 2009 and $0.1 million for the first six months of 2008 from interest rate swap settlements.

Income tax expense (benefit) changed from an expense of $100.5 million in the first six months of 2008 to a benefit of $70.0 million in the first six months of 2009 due to the non-cash ceiling test write down of $281.2 million pre-tax of our oil and natural gas properties during the quarter ended March 31, 2009 as a result of declines in commodity prices. Our effective tax rate for the first six months of 2009 was 37.8% versus 37.0% for the first six months of 2008. The portion of our taxes reflected as current income tax expense for the first six months of 2009 was $1.2 million or 2% of total income tax expense in the six months of 2009 as compared with $25.1 million or 25% of total income tax expense in the first six months of 2008. The reduction in the percentage of tax expense recognized as current is the result of less taxable income projected for 2009. Income taxes paid in the first six months of 2009 were $1.8 million.

Safe Harbor Statement

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by or on our behalf, contain, or may contain, certain statements that are "forward-looking statements" within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which we expect or anticipate will or may occur in the future are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" a similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- our exploration prospects;
- estimates of our proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas reserves;
- growth potential for our mid-stream operations;
- gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates; and
- our belief that the final outcome of our legal proceedings will not materially affect our financial results.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- the time period associated with the current decrease in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Our operations are exposed to market risks primarily because of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, the prices we received for our oil and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first six months 2009 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $371,000 per month ($4.5 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $109,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $124,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow.

We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our production is based, in part, on our view of current and future market conditions. For 2009, in an attempt to better manage our cash flows, we increased the amount of our hedged production through various financial transactions that hedge the future prices we would receive for that production. These transactions include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we will settle the difference with the counterparty to the collars. These financial hedging activities are intended to support oil and gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

At June 30, 2009, the following cash flow hedges were outstanding:

Oil and Natural Gas Segment:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'09 – Dec'09	Crude oil - collar	500 Bbl/day	$100.00 put & $156.25 call	WTI – NYMEX
Jul'09 – Dec'09	Crude oil – swap	2,000 Bbl/day	$51.87	WTI – NYMEX
Jul'09 – Dec'09	Natural gas - collar	10,000 MMBtu/day	$ 8.22 put & $10.80 call	IF – NYMEX (HH)
Jul'09 – Dec'09	Natural gas – swap	30,000 MMBtu/day	$ 7.01	IF – Tenn Zone 0
Jul'09 – Dec'09	Natural gas – swap	30,000 MMBtu/day	$ 6.32	IF – CEGT
Jul'09 – Dec'09	Natural gas – swap	25,000 MMBtu/day	$ 5.57	IF – PEPL
Jan'10 – Dec'10	Crude oil - collar	500 Bbl/day	$65.00 put & $74.85 call	WTI – NYMEX
		1,500 Bbl/day	$61.36	WTI – NYMEX

Jan'10 – Dec'10	Crude oil – swap			
Jan'10 – Dec'10	Natural gas – swap	15,000 MMBtu/day	$ 7.20	IF – NYMEX (HH)
Jan'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	$ 6.89	IF – Tenn Zone 0
Jan'10 – Dec'10	Natural gas – swap	30,000 MMBtu/day	$ 6.12	IF – CEGT
Jan'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	$ 5.67	IF – PEPL
Jan'10 – Dec'10	Natural gas – basis differential swap	10,000 MMBtu/day	($0.79)	PEPL – NYMEX

At June 30, 2009, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jul'09 – Dec'09	Natural gas – basis differential swap	10,000 MMBtu/day	($1.02)	PEPL – NYMEX
Jul'09 – Dec'09	Natural gas – basis differential swap	10,000 MMBtu/day	($1.10)	CEGT – NYMEX

After June 30, 2009, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
Jul'09	Liquids – swap (1)	735,168 Gal/mo	$0.66	OPIS – Mont Belvieu
Jul'09	Liquids – swap (1)	555,072 Gal/mo	$0.63	OPIS – Conway
Aug'09 – Dec'09	Liquids – swap (1)	1,723,050 Gal/mo	$0.66	OPIS – Mont Belvieu
Aug'09 – Dec'09	Liquids – swap (1)	1,300,950 Gal/mo	$0.65	OPIS – Conway

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(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and natural butane.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving Credit Facility may be fixed at the LIBOR Rate for periods of up to 180 days. To help manage our exposure to any future interest rate volatility, we currently have two $15.0 million interest rate swaps, one at a fixed rate of 4.53% and one at a fixed rate of 4.16%, both expiring in May 2012. Based on our average outstanding long-term debt subject to the floating rate in the first six months of 2009, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $1.4 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of June 30, 2009 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended June 30, 2009 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, as defined in Rule 13a – 15(f) under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to certain litigation arising in the ordinary course of our business. Although the amount of any liability that could arise with respect to these actions cannot be accurately predicted, in our opinion, any such liability will not have a material adverse effect on our business, financial condition and/or operating results.

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed below and in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2008, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2008.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information relating to our repurchase of common stock for the three months ended June 30, 2009:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2009 to April 30, 2009	—	$ —	—	—
May 1, 2009 to May 31, 2009	—	—	—	—
June 1, 2009 to June 30, 2009	269	35.03	269	—
Total	269	$ 35.03	269	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the June 11, 2009 vesting distribution for grants previously made from our "Unit Corporation Stock and Incentive Compensation Plan" adopted May 3, 2006.

(2) The price paid per common share represents the closing sales price of a share of our common stock as reported by the NYSE on the day that the stock was acquired by us.

Item 3. Defaults Upon Senior Securities

Not applicable.

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

On May 6, 2009, we held our Annual Meeting of Stockholders. At that meeting the following matters were voted on, with each receiving the votes indicated:

I. Election of Director Nominees John G. Nikkel, Gary R. Christopher and Robert J. Sullivan Jr. for a three-year term expiring in 2012.

Nominee	Numbers of Votes For	Against or Withheld
John G. Nikkel	35,450,371	6,262,883
	35,632,969	6,080,285

Gary R. Christopher		
Robert J. Sullivan Jr.	35,775,326	5,937,928

The following directors, whose term of office did not expire at the annual meeting, continue as directors of the Company: William B. Morgan, John H. Williams, Larry D. Pinkston, King P. Kirchner, J. Michael Adcock and Steven B. Hildebrand.

II. Ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year 2009.

For -	41,340,949
Against -	325,582
Abstain -	49,633

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Item 5. Other Information

Not applicable.

Item 6. Exhibits

Exhibits:

15 Letter re: Unaudited Interim Financial Information.

31.1 Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act.

31.2 Certification of Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act.

32 Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

	Unit Corporation
Date: August 4, 2009	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: August 4, 2009	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer