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 March 31, 2010

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

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

Yes [ ] No [x]

As of April 30, 2010, 47,838,980 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 their 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 on 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)

	March 31, 2010	December 31, 2009
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,039	$ 1,140
Restricted cash	20	20
Accounts receivable, net of allowance for doubtful accounts of $5,186 at March 31, 2010 and December 31, 2009	87,686	74,382
Materials and supplies	6,669	6,914
Current derivative assets (Note 9)	40,210	9,945
Current income tax receivable	15,894	15,236
Current deferred tax asset	14,423	14,423
Prepaid expenses and other	4,780	6,035
Total current assets	170,721	128,095
Property and equipment:		
Drilling equipment	1,224,646	1,217,361
Oil and natural gas properties on the full cost method:		
Proved properties	2,360,943	2,309,193
Undeveloped leasehold not being amortized	146,940	140,129
Gas gathering and processing equipment	179,440	172,549
Transportation equipment	30,718	30,726
Other	22,856	22,747
	3,965,543	3,892,705
Less accumulated depreciation, depletion, amortization and impairment	1,901,659	1,879,112
Net property and equipment	2,063,884	2,013,593
Goodwill	62,808	62,808
Other intangible assets, net	4,795	5,633
Non-current derivative assets (Note 9)	1,511	—
Other assets	17,451	18,270
Total assets	$ 2,321,170	$ 2,228,399

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

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

	March 31, 2010	December 31, 2009
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 63,219	$ 55,880
Accrued liabilities (Note 4)	38,758	34,571
Contract advances	1,587	3,124
Current portion of derivative liabilities (Note 9)	932	2,230
Current portion of other liabilities (Note 5)	10,155	9,342
Total current liabilities	114,651	105,147
Long-term debt (Note 5)	30,000	30,000
Long-term derivative liabilities (Note 9)	1,087	1,142
Other long-term liabilities (Note 5)	80,252	79,984
Deferred income taxes	466,697	446,316
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, 47,841,710 and 47,530,669 shares issued, respectively	9,430	9,405
Capital in excess of par value	390,706	383,957
Accumulated other comprehensive income	24,204	4,458
Retained earnings	1,204,143	1,167,990
Total shareholders' equity	1,628,483	1,565,810
Total liabilities and shareholders' equity	$ 2,321,170	$ 2,228,399

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

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

	Three Months Ended March 31,	
	2010	**2009**
	(In thousands)	
Revenues:		
Contract drilling	$ 60,854	$ 88,699
Oil and natural gas	99,053	88,904
Gas gathering and processing	41,135	22,143
Other	5,508	1,316
Total revenues	206,550	201,062
Expenses:		
Contract drilling:		
Operating costs	40,900	50,330
Depreciation	13,786	12,619
Oil and natural gas:		
Operating costs	25,034	24,816
Depreciation, depletion and amortization	25,336	38,006
Impairment of oil and natural gas properties (Note 2)	—	281,241
Gas gathering and processing:		
Operating costs	32,726	20,677
Depreciation and amortization	3,941	4,061
General and administrative	6,279	6,089
Interest, net	—	477
Total operating expenses	148,002	438,316
Income (loss) before income taxes	58,548	(237,254)
Income tax expense (benefit):		
Current	2,240	—
Deferred	20,155	(89,761)
Total income taxes	22,395	(89,761)
Net income (loss)	$ 36,153	$ (147,493)
Net income (loss) per common share:		
Basic	$ 0.77	$ (3.14)
Diluted	$ 0.76	$ (3.14)

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

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(In thousands)	
OPERATING ACTIVITIES:		
Net income (loss)	$ 36,153	$ (147,493)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	43,313	54,958
Impairment of oil and natural gas properties (Note 2)	—	281,241
Unrealized (gain) loss on derivatives	(1,148)	1,968
Deferred tax expense (benefit)	20,155	(89,761)
(Gain) loss on disposition of assets	(5,435)	(1,304)
Stock compensation plans	3,316	3,134
Other	676	639
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(13,304)	61,832
Accounts payable	966	1,204
Material and supplies inventory	245	(513)
Accrued liabilities	(4,269)	(2,423)
Contract advances	(1,537)	(327)
Other – net	536	9,735
Net cash provided by operating activities	79,667	172,890
INVESTING ACTIVITIES:		
Capital expenditures	(105,563)	(115,904)
Proceeds from disposition of assets	18,313	3,870
Other - net	324	—
Net cash used in investing activities	(86,926)	(112,034)
FINANCING ACTIVITIES:		
Borrowings under line of credit	19,100	50,800
Payments under line of credit	(19,100)	(86,800)
Proceeds from exercise of stock options	246	17
Book overdrafts	6,912	(24,445)
Net cash provided by (used in) financing activities	7,158	(60,428)
Net increase (decrease) in cash and cash equivalents	(101)	428
Cash and cash equivalents, beginning of period	1,140	584
Cash and cash equivalents, end of period	$ 1,039	$ 1,012

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

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

	Three Months Ended March 31,	
	2010	2009
	(In thousands)	
Net income (loss)	$ 36,153	$ (147,493)
Other comprehensive income (loss), net of taxes:		
Change in value of derivative instruments used as cash flow hedges, net of tax of $14,667 and $29,406	23,672	49,005
Reclassification - derivative settlements, Net of tax of ($2,014) and ($9,847)	(3,252)	(16,554)
Ineffective portion of derivatives, net of tax of ($417) and $16	(674)	28
Comprehensive income (loss)	$ 55,899	$ (115,014)

The accompanying notes are an integral part of these 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 condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This quarterly report should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 23, 2010, for the year ended December 31, 2009.

In the opinion of management, the accompanying unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state the following:

- Balance Sheets at March 31, 2010 and December 31, 2009;
- Statements of Operations for the three months ended March 31, 2010 and 2009; and
- Cash Flows for the three months ended March 31, 2010 and 2009.
- Statements of Comprehensive Income (Loss) for the three months ended March 31, 2010 and 2009.

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 may differ from those estimates. Results for the three months ended March 31, 2010 and 2009 are not necessarily indicative of the results to be realized for the full year in the case of 2010, or that we realized for the full year of 2009.

With respect to our unaudited financial information for the three month periods ended March 31, 2010 and 2009, 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 May 4, 2010, 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 degree of reliance placed on its report of such information 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 (Act) 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

Full cost accounting rules require us to review the carrying value of our oil and natural gas properties at the end of each quarter. 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%. Effective December 31, 2009, full cost companies must use the unweighted arithmetic average of the price on the first day of the month for each month within the 12-month period before the end of the reporting period, unless prices were defined by contractual arrangements, to calculate discounted future revenues. Previously, the price used was the single-day period-end price. In the event the unamortized cost of the oil and natural gas properties being amortized exceeds the full cost ceiling, the excess amount 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 that ended March 31, 2009. This write down resulted from the decline in commodity prices as compared to prices existing at the end of 2008. At March 31, 2010, 12-month average commodity prices, including the discounted value of our commodity hedges, were at levels that did not require us to take a write-down of the value of our oil and natural gas properties. However if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, a write-down of the carrying value of our oil and natural gas properties may be required in future periods.

Derivative instruments qualifying as cash flow hedges were included in determining the limitation on the capitalized costs in our March 31, 2009 ceiling test calculation. The effect of including those hedges was a $197.9 million pre-tax increase in the discounted net cash flow of our oil and natural gas properties. Our qualifying cash flow hedges as of March 31, 2009, which consisted of swaps and collars, covered 30.3 Billion cubic feet of natural gas equivalent (Bcfe) and 33.2 Bcfe in 2009 and 2010, respectively.

We did not have a ceiling test write down for the quarter ended March 31, 2010. Our qualifying cash flow hedges as of March 31, 2010, which consisted of swaps and collars, covered 36.5 Bcfe in 2010, 5.5 Bcfe in 2011 and 5.5 Bcfe in 2012. The effect of those hedges was a $70.1 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Without the impact of the hedges, there still would not be a write down for the first quarter of 2010. Our oil and natural gas hedging is discussed in Note 9 of the Notes to our 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 March 31, 2010:			
Basic earnings per common share	$ 36,153	47,121	$ 0.77
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	—	565	(0.01)
Diluted earnings per common share	$ 36,153	47,686	$ 0.76
For the three months ended March 31, 2009:			
Basic earnings (loss) per common share	$ (147,493)	46,921	$ (3.14)
Effect of dilutive stock options, restricted stock and stock appreciation rights	—	—	—
Diluted earnings (loss) per common share	$ (147,493)	46,921	$ (3.14)

Because we had a net loss for the three months ended March 31, 2009, approximately 216,000 weighted average shares related to stock options and SARs were antidilutive and not included in the calculation of earnings per share above. The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended March 31,	
	2010	2009
Stock options and SARs	132,165	374,921
Average Exercise Price	$ 59.87	$ 47.09

NOTE 4 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2010	December 31, 2009
	(In thousands)	
Employee costs	$ 7,278	$ 13,307
Lease operating expense accrual	5,506	6,244
Taxes	18,006	5,085
Other	7,968	9,935
Total accrued liabilities	$ 38,758	$ 34,571

NOTE 5 – 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:

	March 31, 2010	December 31, 2009
	(In thousands)	
Revolving credit facility with interest, including the effect of hedging, of 6.1% at March 31, 2010 and 4.3% at December 31, 2009	$ 30,000	$ 30,000
Less current portion	—	—
Total long-term debt	$ 30,000	$ 30,000

Our existing bank credit agreement (Credit Facility) has a maximum credit amount of $400.0 million maturing on May 24, 2012. The lenders' commitment under the Credit Facility is $325.0 million. Our borrowings under the Credit Facility are limited to the commitment amount that we elect. As of March 31, 2010, 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 amount of the total borrowing base. To date we have paid $1,215,625 in origination, agency and syndication fees under the Credit Facility. These fees are being amortized over the life of the agreement.

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 April 1, 2010 redetermination set the borrowing base at $500.0 million. 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 completion of an acquisition that meets the requirements set forth 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 period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of 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 March 31, 2010, all of our $30.0 million in outstanding borrowings 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 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 March 31, 2010, 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 March 31, 2010 approximates its fair value.

At March 31, 2010, the carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the condensed consolidated balance sheets approximate fair value because of their short term nature.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2010	December 31, 2009
	(In thousands)	
Asset retirement obligations (ARO) liability	$ 57,342	$ 56,404
Workers' compensation	22,979	22,974
Separation benefit plans	4,757	4,681
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,066	2,004
	90,407	89,326
Less current portion	10,155	9,342
Total other long-term liabilities	$ 80,252	$ 79,984

The estimated total annual principal payments due under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2010 (and through 2015) are $10.2 million, $17.1 million, $33.5 million, $2.8 million and $2.5 million, respectively.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

We are required to record the fair value of liabilities associated with the future retirement of our long-lived assets. Our oil and natural gas wells are required to be plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment expense for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs.

The following table shows certain information about our AROs for the periods indicated:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
	(In thousands)	
ARO liability, January 1:	$ 56,404	$ 49,230
Accretion of discount	687	632
Liability incurred	472	898
Liability settled	(270)	(202)
Revision of estimates	49	40
ARO liability, March 31:	57,342	50,598
Less current portion	1,632	1,135
Total long-term plugging liability	$ 55,710	$ 49,463

NOTE 7 - NEW ACCOUNTING PRONOUNCEMENTS

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 – *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures--Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU is the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement will not have a significant impact on us due to it only requiring enhanced disclosures.

NOTE 8 – STOCK-BASED COMPENSATION

For the three months ended March 31, 2010 and 2009, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.5 million and $1.9 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.5 million and $0.6 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $0.9 million and $0.7 million, respectively. The remaining unrecognized compensation cost related to unvested awards at March 31, 2010 is approximately $12.4 million with $2.7 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.7 years.

We did not grant any stock options or SARs during either of the three month periods ending March 31, 2010 and 2009.

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

	Three Months Ended March 31,	
	2010	2009
Shares granted	248,383	—
Estimated fair value (in millions)	$ 10.6	$ —
Percentage of shares granted Expected to be distributed	93%	—%

The restricted stock awards granted during the first three months of 2010 increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first quarter of 2010 by an aggregate of $1.4 million.

NOTE 9 – DERIVATIVES

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases. Under these transactions we swap the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest. As of March 31, 2010, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. This table provides certain information about our interest rate swaps:

Term	Amount	Fixed Rate	Floating Rate
April 2010 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
April 2010 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative instruments covering some of our projected production of natural gas, natural gas liquids and oil. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) that we will receive for that production. Our decision on the type and quantity of our production and the price(s) of our hedge is based, in part, on our view of current and future market conditions. As of March 31, 2010, 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 or from 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 March 31, 2010, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr'10 – Dec'10	Crude oil - collar	1,000 Bbl/day	$67.50 put & $81.53 call	WTI – NYMEX
Apr'10 – Dec'10	Crude oil – swap	1,500 Bbl/day	$61.36	WTI – NYMEX
Apr'10 – Dec'10	Natural gas – swap	15,000 MMBtu/day	$ 7.20	IF – NYMEX (HH)
Apr'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	$ 6.89	IF – Tenn Zone 0
Apr'10 – Dec'10	Natural gas – swap	30,000 MMBtu/day	$ 6.12	IF – CEGT
Apr'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	$ 5.67	IF – PEPL
Apr'10 – Dec'10	Natural gas – basis differential swap	10,000 MMBtu/day	($0.79)	PEPL – NYMEX
Jan'11 – Dec'11	Natural gas – swap	15,000 MMBtu/day	$ 5.56	IF – NYMEX (HH)
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 – NYMEX
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$ 5.62	IF – PEPL

At March 31, 2010, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 – NYMEX
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($0.21)	CEGT – NYMEX
Jan'11 – Dec'11	Natural gas – basis differential swap	10,000 MMBtu/day	($0.225)	PEPL – NYMEX

After March 31, 2010, we entered into the following cash flow hedge:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
May'10–Dec'11	Liquids – swap (1)	644,406 Gal/mo	$0.97	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 within our balance sheets where these derivative instruments are recorded:

	Balance Sheet Location	Derivative Assets Fair Value March 31, 2010	Derivative Assets Fair Value December 31, 2009
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 40,196	$ 9,945
Long-term	Non-current derivative assets	1,468	—
Total derivatives designated as hedging instruments		41,664	9,945
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current derivative assets	14	—
Long-term	Non-current derivative assets	43	—
Total derivatives not designated as hedging instruments		57	—
Total derivative assets		$ 41,721	$ 9,945

	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2010	Derivative Liabilities Fair Value December 31, 2009
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 932	$ 806
Long-term	Other long-term derivative liabilities	1,087	1,142
Commodity derivatives:			
Current	Current portion of derivative liabilities	—	1,424
Total derivatives designated as hedging instruments		2,019	3,372
Total derivatives not designated as hedging instruments		—	—
Total derivative liabilities		$ 2,019	$ 3,372

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our balance sheets.

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2010 and 2009, we had a gain of $24.2 million and $65.8 million, net of tax, respectively, in accumulated OCI.

Based on market prices at March 31, 2010, we expect to transfer to earnings approximately $24.3 million, net of tax, of the gain included in accumulated OCI during the next 12 months in the related month of settlement. The interest rate swaps and the commodity derivative instruments existing as of March 31, 2010 are expected to mature by May 2012 and December 2012, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these types of derivatives, any changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within our 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 our oil and natural gas revenues.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (cash flow hedges) for the three months ended March 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) [(1)]	
	2010	2009
	(In thousands)	
Interest rate swaps	$ (1,247)	$ (1,555)
Commodity derivatives	25,451	67,318
Total	$ 24,204	$ 65,763

(1) Net of taxes.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations (cash flow hedges) for the three months ended March 31:

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)]	
		2010	2009	2010	2009
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 5,573	$ 26,589	$ 1,091	$ (44)
Interest rate swaps	Interest, net	(307)	(188)	—	—
	Total	$ 5,266	$ 26,401	$ 1,091	$ (44)

(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) for the three months ended March 31:

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	
		2010	2009
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ 57	$ (1,108)
Total		$ 57	$ (1,108)

NOTE 10 – FAIR VALUE MEASUREMENTS

Fair value is defined 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 (in either case, 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 tables set forth our recurring fair value measurements:

	March 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ —	$ —	$ (2,019)	$ (2,019)
Commodity derivatives	$ —	$ (9,718)	$ 51,439	$ 41,721

	December 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ —	$ —	$ (1,948)	$ (1,948)
Commodity derivatives	$ —	$ (11,427)	$ 19,948	$ 8,521

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. We measure the fair values of our crude oil swaps using estimated internal discounted cash flow calculations based on the 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 against established index prices and other sources.

Commodity Derivatives. The fair values of our natural gas and natural gas liquids 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.

The following tables are reconciliations of our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended March 31, 2010		For the Three Months Ended March 31, 2009	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,948)	$ 19,948	$ (2,516)	$ 58,508
Total gains or losses (realized and unrealized):				
Included in earnings (loss) [(1)]	(307)	9,074	(188)	23,878
Included in other comprehensive income (loss)	(71)	30,343	37	52,873
Purchases, issuance and settlements	307	(7,926)	188	(25,846)
End of period	$ (2,019)	$ 51,439	$ (2,479)	$ 109,413
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held at end of period	$ —	$ 1,148	$ —	$ (1,968)

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

Based on our valuation at March 31, 2010, we determined that the non-performance risk with regard to our counterparties was immaterial.

NOTE 11 - 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 each segment's performance 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.

The following table provides certain information about the operations of each of our segments:

	Three Months Ended March 31, 2010	2009
	(In thousands)	
Revenues:		
Contract drilling	$ 67,501	$ 91,324
Elimination of inter-segment revenue	(6,647)	(2,625)
Contract drilling net of inter-segment revenue	60,854	88,699
Oil and natural gas	99,053	88,904
Gas gathering and processing	53,734	30,656
Elimination of inter-segment revenue	(12,599)	(8,513)
Gas gathering and processing net of inter-segment revenue	41,135	22,143
Other	5,508	1,316
Total revenues	$ 206,550	$ 201,062
Operating income (loss) (1):		
Contract drilling	$ 6,168	$ 25,750
Oil and natural gas (2)	48,683	(255,159)
Gas gathering and processing	4,468	(2,595)
Total operating income (loss)	59,319	(232,004)
General and administrative expense	(6,279)	(6,089)
Interest expense, net	—	(477)
Other	5,508	1,316
Income (loss) before income taxes	$ 58,548	$ (237,254)

(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 incurred a $281.2 million pre-tax ($175.1 million net of tax) non-cash write down of our oil and natural gas properties due to low commodity prices existing 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 March 31, 2010, and the related condensed consolidated statements of operations and comprehensive income (loss) for the three-month periods ended March 31, 2010 and 2009 and the condensed consolidated statements of cash flows for the three-month periods ended March 31, 2010 and 2009. 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, 2009, and the related consolidated statements of operations, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 23, 2010, 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, 2009, 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
May 4, 2010

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 our operating results and financial condition by focusing on changes in certain key measures from year to year. We have organized MD&A into the following sections:

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

MD&A should be read in combination with the condensed consolidated financial statements and related notes included in this report and 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 or, as appropriate, one or more of its subsidiaries.

General

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 consolidated business, as well as each of our three operating segments depends, on a large part, on: the prices received for our natural gas, natural gas liquids and oil production; the demand for oil and natural gas; and the demand for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. While to date all of our operations (with the exception of a minor amount of production in Canada) are located within the United States, events outside the United States can and do impact us and our industry.

In addition to their direct impact on us, low commodity prices if sustained for a long period of time could impact the liquidity of some of our industry partners and customers which, in turn, could limit their ability to meet their financial obligations to us.

The slowdown in the United States and world economies starting in late 2008 resulted in less demand for oil and natural gas products by those industries and consumers that use those products in their businesses. The long-term impact on our business and financial results as a consequence of the volatility in oil and natural gas prices and the global economic downturn is uncertain.

The following table reflects the recent fluctuations in the prices for oil and natural gas:

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
June 1, 2009	$ 3.93	$ 68.58
July 1, 2009	$ 3.72	$ 69.31
August 1, 2009	$ 3.34	$ 69.45
September 1, 2009	$ 2.41	$ 68.05
October 1, 2009	$ 3.24	$ 70.82
November 1, 2009	$ 4.10	$ 77.00
December 1, 2009	$ 4.40	$ 78.37
January 1, 2010	$ 5.79	$ 79.36
February 1, 2010	$ 5.26	$ 74.43
March 1, 2010	$ 4.77	$ 78.70
April 1, 2010	$ 3.93	$ 84.47

As noted in the table above, oil and natural gas prices declined significantly after their July 2008 levels before they began to reverse that trend by the end of 2009. Our initial 2010 operating budget is based on oil and natural gas prices averaging $72.00 per Bbl and $5.30 per Mcf, respectively, for the year; however, we will continue to monitor prices and may consider updates to the budget as necessary. We expect to fund our 2010 operating budget using internally generated cash flow and to a lesser extent from borrowings under our credit facility.

The impact on the use of our drilling rigs and dayrates because of the decline in commodity prices is reflected in the following table.

Period	Average Rigs in Use	Average Dayrates (1)
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
July 2009	31.4	$ 15,460
August 2009	35.3	$ 15,357
September 2009	37.1	$ 15,275
October 2009	36.5	$ 14,942
November 2009	35.9	$ 14,996
December 2009	37.7	$ 14,234
January 2010	46.5	$ 14,004
February 2010	51.6	$ 14,066
March 2010	54.7	$ 14,278

(1) As of March 2010, the average dayrates include 32 term contracts, of which 13 are up for renewal during 2010, 18 are up for renewal in 2011 and the remaining one in 2012.

Executive Summary

Contract Drilling

Our first quarter 2010 utilization rate was 40%, compared to 28% and 40% in the fourth quarter of 2009 and the first quarter 2009, respectively. Dayrates for the first quarter of 2010 averaged $14,127, a decrease of 4% from the fourth quarter of 2009 and 24% from the first quarter of 2009. Direct profit (contract drilling revenue less contract drilling operating expense) increased 15% from the fourth quarter of 2009 and decreased 48% from the first quarter of 2009. The increase was primarily due to the increase in utilization over the fourth quarter of 2009 and the decrease from the first quarter of 2009 was primarily due to the decrease in dayrates over the comparative periods. Operating cost per day decreased 1% from the fourth quarter of 2009 and decreased 16% from the first quarter of 2009. The decrease from the fourth quarter 2009 was primarily due to decreases in the per day general and administrative expenses. The decrease from the first quarter of 2009 was primarily due to decreased per day direct cost and decreases in workers' compensation costs. While we experienced increased drilling activity and spending by our customers during the first quarter of 2010, the decline in natural gas prices over the first quarter if sustained could limit further increases and result in reduced activity through 2010.

In January and February 2010, our contract drilling segment entered into contracts to sell eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horse power from 800 to 1,000. The closing on six of these drilling rigs occurred in the first quarter. The last transaction for the remaining two rigs is expected to close in the second quarter of 2010. Proceeds from the sale of those drilling rigs will be $23.9 million with an estimated gain of $5.7 million. These proceeds will be used to refurbish and upgrade additional drilling rigs in our fleet allowing those rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer. After the completion of the sale of the eight rigs and with the additional rig recently placed into service, this segment will have 123 drilling rigs in its fleet.

Our anticipated 2010 capital expenditures for this segment are $76.0 million.

Oil and Natural Gas

First quarter 2010 production from our oil and natural gas segment was 157,000 Mcfe per day, a 1% increase over the fourth quarter of 2009 and a 13% decrease over the first quarter of 2009. The decrease in production from first quarter 2009 is primarily due to the natural declines in production and the reduction in reserve replacement after slowing our development drilling program through most of 2009 due to the downturn in commodity prices.

First quarter 2010 oil and natural gas revenues increased 9% from the fourth quarter of 2009 and increased 11% from the first quarter of 2009. Our oil, natural gas and NGL prices in the first quarter of 2010, increased 9%, 3% and 64%, respectively, from the fourth quarter of 2009 and our oil, natural gas and NGL prices increased 33%, 9% and 129%, respectively, from the first quarter of 2009. Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 13% from the fourth quarter of 2009 and increased 15% from the first quarter of 2009. The increases from the fourth quarter 2009 and the first quarter 2009 were primarily attributable to increases in oil and liquids prices and to a lesser extent natural gas prices. Operating cost per Mcfe produced increased 2% from the fourth quarter of 2009 and 16% from the first quarter of 2009 due to the increase in production taxes due to increased commodity prices.

For 2010, we hedged 74% of our average daily oil production (based on our first quarter 2010 production) and approximately 74% of our average natural gas production (based on our first quarter 2010 production) to help manage our cash flow and capital expenditure requirements. Currently for 2011 and 2012, we have hedged 13% for each year of our average natural gas production (based on our first quarter 2010 production) and currently do not have any oil hedges in place for these years.

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 March 31, 2010, the 12-month average of commodity prices, including the discounted value of our commodity hedges, were at levels that did not require us to record a write-down of our oil and natural gas properties. Prior to December 31, 2009, the price was based on the single-day period-end price. Effective December 31, 2009, SEC reserve reporting rules require the use of a 12-month average price. The revision to the 12-month average price was made to reduce the affect of short-term volatility and seasonality that previously occurred with single-day pricing. Using the 12-month average may or may not result in write-downs that would have been required had the single-day period-end price been used. Should the 12-month average for commodity prices decline below those existing at the period-end, including the discounted value of our commodity hedges, a write-down of the carrying value of our oil and natural gas properties could be required in future periods.

Our first quarter 2010 drilling activity was slowed down by unusually wet weather, especially in the Texas Panhandle Granite Wash play, and operational delays as we transition to drilling primarily horizontal wells. In addition, we are experiencing delays in completing wells due to shortages in fracture stimulation services. As a result of these conditions, we have reduced our 2010 production guidance to approximately 64.0 to 65.0 Bcfe, an increase of 5% to 7% from our 2009 production. The number of wells we plan to participate in drilling and the level of capital expenditures remains unchanged for 2010 at 175 wells and $365 million, respectively.

In the third quarter of 2008, commodity prices started to decrease substantially and continued to decline into the third quarter of 2009. As a result of these lower commodity prices and the relatively high costs for well drilling services, we decided to reduce our drilling activity during the fourth quarter of 2008 and continued to do so through the second quarter of 2009. We began increasing activity during the third quarter of 2009 and plan to continue to increase activity throughout 2010.

Mid-Stream

First quarter 2010 liquids sold per day decreased 4% from the fourth quarter of 2009 and increased 16% from the first quarter of 2009. Liquids sold per day decreased from the fourth quarter of 2009 primarily due to reduced liquid recoveries on wells within the system and for down time maintenance at one of our plants, and increased from the first quarter of 2009 primarily as the result of upgrades and expansions to existing plants and the connection of new wells. Gas processed per day was essentially unchanged from the fourth quarter of 2009 and increased 5% over the first quarter of 2009. In 2009, we upgraded several of our existing processing facilities and added three processing plants which was the primary reason for increased volumes. Gas gathered per day increased 2% from the fourth quarter of 2009 due to additional well connects and decreased 6% from the first quarter of 2009 primarily from our gathering systems experiencing natural production declines associated with connected wells.

NGL prices in the first quarter of 2010 increased 9% from the price received in the fourth quarter of 2009 and 81% over the price received in the first quarter of 2009. 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. We currently do not have any fractionation spread hedges in place for 2010 and beyond.

Direct profit (mid-stream revenues less mid-stream operating expense) decreased 7% from the fourth quarter of 2009 and increased 474% from the first quarter of 2009. The decrease from the fourth quarter 2009 was due to lower volumes and the increase from the first quarter 2009 resulted primarily from increased commodity prices. Total operating cost for our mid-stream segment increased 17% from the fourth quarter of 2009 and increased 58% from the first quarter of 2009 due primarily to the increase in the price paid for the purchase of natural gas.

Our anticipated capital expenditures for 2010 for this segment are $53.0 million. For 2010, we anticipate an increase in well connections due to anticipated drilling activity by operators in the areas of our existing gathering systems as well as adding an additional processing facility to accommodate the increased drilling activity of our oil and natural gas segment.

Financial Condition and Liquidity

Summary. Our financial condition and liquidity depends on the cash flow from our operations and, when necessary, borrowings under our Credit Facility. The principal factors determining the amount of our cash flow are:

- 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 March 31, 2010 and 2009 and for the three months ended March 31, 2010 and 2009:

	March 31, 2010	March 31, 2009	% Change
	(In thousands except percentages)		
Working capital	$ 56,070	$ 103,001	(46)%
Long-term debt	$ 30,000	$ 163,500	(82)%
Shareholders' equity [(1)]	$ 1,628,483	$ 1,528,917	7 %
Ratio of long-term debt to total capitalization [(1)]	2 %	10 %	(81)%
Net income (loss) [(1)]	$ 36,153	$ (147,493)	125 %
Net cash provided by operating activities	$ 79,667	$ 172,890	(54)%
Net cash used in investing activities	$ (86,926)	$ (112,034)	(22)%
Net cash provided by (used in) financing activities	$ 7,158	$ (60,428)	112 %

(1) In March 2009, we incurred a $281.2 million pre-tax ($175.1 million net of tax) non-cash ceiling test write down of our oil and natural gas properties 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. The write down did not impact our compliance with the covenants contained in our Credit Facility.

The following table summarizes certain operating information:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	50.9	52.8	(4)%
Total number of drilling rigs owned at the end of the period	125	131	(5)%
Average dayrate	$ 14,127	$ 18,638	(24)%
Oil and Natural Gas:			
Oil production (MBbls)	303	343	(12)%
Natural gas liquids production (MBbls)	377	393	(4)%
Natural gas production (MMcf)	10,034	11,862	(15)%
Average oil price per barrel received	$ 67.33	$ 50.51	33%
Average oil price per barrel received excluding hedges	$ 75.70	$ 38.52	97%
Average NGL price per barrel received	$ 42.76	$ 18.69	129%
Average NGL price per barrel received excluding hedges	$ 42.76	$ 18.69	129%
Average natural gas price per mcf received	$ 5.95	$ 5.44	9%
Average natural gas price per mcf received excluding hedges	$ 5.14	$ 3.48	48%
Mid-Stream:			
Gas gathered—MMBtu/day	180,117	192,320	(6)%
Gas processed—MMBtu/day	76,513	72,650	5%
Gas liquids sold — gallons/day	253,707	218,762	16%
Number of natural gas gathering systems	33	37	(11)%
Number of processing plants	8	9	(11)%

At March 31, 2010, we had unrestricted cash totaling $1.0 million and we had borrowed $30.0 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. Before 2009, most of our capital expenditures were discretionary and directed toward future growth. Beginning in the fourth quarter of 2008 and continuing through 2009, we significantly reduced our capital expenditures because of the uncertain economic environment. For 2010, we plan to increase our capital expenditures, focusing on growth and funded mainly through internally generated cash flow and to a lesser extent from borrowings under the credit facility.

Working Capital. Typically, our working capital balance fluctuates primarily because of the timing of our trade accounts receivable and accounts payable and from the fluctuation in current assets and liabilities associated with the mark to market value of our hedging activity. We had working capital of $56.1 million and $103.0 million as of March 31, 2010 and 2009, respectively. The effect of our hedging activity increased working capital by $24.3 million and $52.3 million as of March 31, 2010 and 2009, respectively.

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.

During 2009, competition to keep and attract qualified employees to meet our requirements did not materially affect us due to the depressed conditions within our industry. If current commodity price and industry drilling utilization rates continue, we do not anticipate that our drilling labor costs will increase from those levels in effect at the end of the fourth quarter of 2009. However, if demand for drilling rigs increase, so will the competition to retain and attract qualified labor.

Demand for drilling rigs in the 1,000 to 1,500 horsepower range has increased over the past year as more of our customers shift to drilling horizontal wells, which are suited for this horsepower range. Availability of drilling rigs in this range will also have a larger impact on dayrates in the future. For the first three months of 2010, our average dayrate was $14,127 per day compared to $18,638 per day for the first three months of 2009. The average number of our drilling rigs used in the first quarter of 2010 was 50.9 drilling rigs (40%) compared with 52.8 drilling rigs (40%) in the first quarter of 2009. Based on the average utilization of our drilling rigs during the first three months of 2010, a $100 per day change in dayrates has a $5,090 per day ($1.9 million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong during the second and third quarters of 2008 before the fourth quarter downturn. We expect that utilization and dayrates for our drilling rigs will slowly improve for 2010 compared to 2009 and 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.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. 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 three months of 2010 and 2009, we drilled 9 and 6 wells, respectively, for our exploration and production subsidiary. The profit associated with these wells received by our contract drilling segment of $0.4 million and $0.6 million during the first three months of 2010 and 2009, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Impact of Prices for Our Oil, NGLs and Natural Gas. As of December 31, 2009, natural gas comprised 73% 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 worldwide oil price levels and the value of the U.S. dollar. 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 three months of 2010 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 $320,000 per month ($3.8 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of hedging, during the first three months of 2010 was $5.95 compared to $5.44 for the first three months of 2009. Based on our first three months of 2010 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $96,000 per month ($1.2 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 $121,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow. In the first three months of 2010, our average oil price per barrel received, including the effect of hedging, was $67.33 compared with an average oil price, including the effect of hedging, of $50.51 in the first three months of 2009 and our first three months of 2010 average NGLs price per barrel received was $42.76 compared with an average NGL price per barrel of $18.69 in the first three months of 2009.

Because natural gas prices have such a significant effect on the value of our oil, NGLs and natural gas reserves, declines in those prices can result in a decline in the carrying value of our oil and natural gas properties. 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.

Most of our natural gas production is sold to third parties under month-to-month contracts.

Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiary. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, eight processing plants, 33 gathering systems and 845 miles of pipeline. Superior operates in Oklahoma, Texas, Kansas and Pennsylvania and has been in business since 1996. This segment enhances our ability to gather and market not only our own natural gas but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first three months of 2010 and 2009, our mid-stream operations purchased $11.6 million and $7.0 million, respectively, of our oil and natural gas segment's production and provided gathering and transportation services to it of $1.0 million and $1.5 million, respectively. 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 condensed consolidated financial statements.

Our mid-stream segment gathered an average of 180,117 MMBtu per day in the first quarter of 2010 compared to 192,320 MMBtu per day in the first quarter of 2009, processed volumes were 76,513 MMBtu per day in the first quarter of 2010 compared to 72,650 MMBtu per day in the first quarter of 2009 and the amount of NGLs sold were 253,707 gallons per day in the first quarter of 2010 compared to 218,762 gallons per day in the first quarter of 2009. Gas gathering volumes per day in the first three months of 2010 decreased 6% compared to the first three months of 2009 primarily due to a volumetric decline in gathering systems due to natural production declines associated with the connected wells. Processed volumes increased 5% over the comparative three months and NGLs sold also increased 16% over the comparative period primarily due to the addition of wells connected and recent upgrades to several of our processing systems.

Our Credit Facility. Our existing bank credit agreement (Credit Facility) has a maximum credit amount of $400.0 million maturing on May 24, 2012. The lenders' commitment under the Credit Facility is $325.0 million. Our borrowings under the Credit Facility are limited to the commitment amount that we elect. As of March 31, 2010, 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 amount of the total borrowing base. To date we have paid $1,215,625 in origination, agency and syndication fees under the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for the first quarter of 2010, which includes the effect of our two interest rate swaps, was 6.1% compared to 4.0% for the first three months of 2009. At both March 31, 2010 and April 30, 2010, borrowings were $40.0 million.

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%
BBVA Compass Bank	17.50%
Comerica Bank	08.75%
BNP Paribas	08.75%
Crédit Agricole Corporate and Investment Bank	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 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 April 1, 2010 redetermination set the borrowing base at $500.0 million. 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 completion of an acquisition that meets the requirements set forth 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 period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of 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 March 31, 2010, all of our $30.0 million in outstanding borrowings 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 March 31, 2010, we were in compliance with all the covenants contained in the Credit Facility.

We entered into the following interest rate swaps to manage our exposure to possible future interest rate increases. Under these transactions we swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest.

The table provides certain information about out interest rate swaps:

Term	Amount	Fixed Rate	Floating Rate
April 2010 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
April 2010 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Capital Requirements

Contract Drilling Acquisitions and Capital Expenditures. In January and February 2010, our contract drilling segment entered into contracts to sell eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horse power from 800 to 1,000. The closing on six of these drilling rigs occurred in the first quarter. The last transaction for the remaining two rigs is expected to close in the second quarter of 2010. Proceeds from the sale of those drilling rigs will be $23.9 million with an estimated gain of $5.7 million which was booked in the first quarter 2010. These proceeds will be used to refurbish and upgrade additional drilling rigs in our fleet allowing those rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer. After the completion of the sale of the eight rigs and with the additional rig recently placed into service, this segment will have 123 drilling rigs in its fleet.

Our anticipated 2010 capital expenditures for this segment are $76.0 million. We currently do not have a shortage of drill pipe and drilling equipment. At March 31, 2010, we had commitments to purchase approximately $0.8 million of drilling rig components and $13.8 million of drill pipe and drill collars in 2010. We have spent $39.8 million in capital expenditures as of March 31, 2010.

For 2009, our capital expenditures were $67.7 million. In late 2008, we postponed the construction of eight additional drilling rigs we had previously anticipated building. In the third quarter 2009, we recognized an early termination fee associated with the cancellation of long-term contracts by a customer on two of these eight rigs. In addition, as a result of an existing contractual obligation, we took delivery of a new 1,500 horsepower drilling rig during the fourth quarter of 2009 at a cost of $13.2 million. The customer, who had signed a two year term contract for this rig when it was ordered, opted not to take delivery of the rig and paid an early termination fee under the contract provisions 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 27 gross wells (12.16 net wells) in the first three months of 2010 compared to 21 gross wells (5.43 net wells) in the first three months of 2009. Total capital expenditures for the first three months of 2010 by this segment, excluding a $0.3 million ARO liability, totaled $58.2 million. Currently we plan to participate in drilling an estimated 175 gross wells in 2010 and estimate our total capital expenditures (excluding any possible acquisitions) for our oil and natural gas segment will be approximately $365.0 million. Whether we are able to 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 and include the availability of drilling rigs, 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.

During 2009, we acquired interests in approximately 60,000 net undeveloped acres in the Marcellus Shale Play, located mainly in Pennsylvania and Maryland for approximately $43.6 million. In July 2009, we received $7.1 million and approximately 1,500 net undeveloped acres, representing payment for our 50% interest in 4,000 gross undeveloped acres and reimbursement for costs we paid on behalf of unaffiliated third parties. On September 30, 2009, per our agreement with the third parties, we were paid approximately $14.9 million for our 50% interest in approximately 18,000 gross undeveloped acres of the Marcellus Shale and $26.1 million for a receivable from the third parties for their 50% share of the costs we paid on their behalf to acquire the acreage. The sales proceeds reduced undeveloped leasehold and no gain or loss was recorded on this sale. We now have an interest in approximately 50,500 net undeveloped acres.

As of March 31, 2010, we had commitments to purchase casing for $1.1 million.

Mid-Stream Acquisitions and Capital Expenditures. During the first quarter of 2010, our mid-stream segment incurred $6.9 million in capital expenditures as compared to $5.3 million in the first quarter of 2009. For 2010, we have budgeted capital expenditures of approximately $53.0 million. The increase over 2009 expenditures is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as adding an additional processing facility to accommodate the increased drilling activity of our oil and natural gas segment.

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. Approximately half of the penalty is being applied toward the purchase price of the plant we are constructing in 2010.

Contractual Commitments. At March 31, 2010, 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)	$ 33,928	$ 1,828	$ 32,100	$ —	$ —
Operating leases (2)	6,904	1,690	2,909	2,305	—
Drill pipe, drilling components and equipment purchases (3)	17,512	17,512	—	—	—
Total contractual obligations	$ 58,344	$ 21,030	$ 35,009	$ 2,305	$ —

(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 March 31, 2010 interest rate of 6.1% which includes the effect of the interest rate swaps.

(2) We lease office space or yards in Tulsa, Oklahoma; Houston, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2015. 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 $14.6 million of new drilling rig components, drill pipe, drill collars and related equipment and $1.1 million of casing. Also in 2010, we will pay the remaining $1.8 million towards the purchase of a 50mmcf/d gas plant.

At March 31, 2010, 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)	$ 2,066	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 4,757	$ 140	Unknown	Unknown	Unknown
Derivative liabilities – interest rate swaps	$ 2,019	$ 932	$ 1,087	$ —	$ —
Asset retirement liability (3)	$ 57,342	$ 1,632	$ 17,429	$ 4,152	$ 34,129
Gas balancing liability (4)	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ —	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$ 22,979	$ 8,383	$ 3,185	$ 1,141	$ 10,270

(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.

(3) When a well is drilled or acquired, under "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 for the first quarter of 2010.

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

Derivative Activities. 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 enter into interest rate swaps to manage our exposure to possible future interest rate increases under our Credit Facility. Under these transactions we swap the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest. As of March 31, 2010, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. Our March 31, 2010 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)			
April 2010 – May 2012	$ 15,000	4.53%	3 month LIBOR	$ (1,070)
April 2010 – May 2012	$ 15,000	4.16%	3 month LIBOR	(949)
				$ (2,019)

Because of these interest rate swaps, interest expense increased by $0.3 million and $0.2 million for the three months ended March 31, 2010 and 2009, respectively. A loss of $1.2 million, net of tax, is reflected in accumulated OCI as of March 31, 2010.

Commodity Hedges. Our hedging is intended to reduce price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our hedge(s) is based, in part, on our view of current and future market conditions. Based on our first quarter 2010 average daily production, as of March 31, 2010, the approximated percentages we have hedged are as follows:

Oil and Natural Gas Segment:

	April – December 2010	January – December 2011	January – December 2012
Daily oil production	74%	—%	—%
Daily natural gas production	74%	13%	13%

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. Based on our valuation at March 31, 2010, we determined that the non-performance risk with regard to our counterparties was immaterial. At March 31, 2010, Bank of Montreal, Bank of America, N.A., Crédit Agricole Corporate and Investment Bank, London Branch, Comerica Bank, BBVA Compass Bank and Barclays Capital were the counterparties with respect to all of our commodity derivative transactions. At March 31, 2010, the fair values of the net assets we had with each of these counterparties was $12.3 million, $12.7 million, $4.6 million, $8.9 million, $3.0 million and $0.2 million, respectively.

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our condensed consolidated balance sheets. At March 31, 2010, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $40.2 million and $1.5 million, respectively. At March 31, 2009, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $86.3 million and $22.2 million, respectively, and current and non-current derivative liabilities of $1.6 million and $0.2 million, respectively.

We recognize in accumulated OCI the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2010, we had a gain of $25.4 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 OCI.

Based on market prices at March 31, 2010, we expect to transfer to earnings approximately $24.3 million, net of tax, of the gain included in accumulated OCI during the next 12 months in the related month of production. The interest rate swaps and the commodity derivative instruments existing as of March 31, 2010 are expected to mature by May 2012 and December 2012, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these types of derivatives, any changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within our 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 currently in our 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 for the three months ended March 31:

	2010	2009
	(In thousands)	
Increases (decreases) in:		
Oil and natural gas revenue:		
Realized gains (losses) on oil and natural gas derivatives	$ 5,573	$ 27,405
Unrealized gains (losses) on ineffectiveness of cash flow hedges	1,091	(44)
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	57	(1,924)
Total increase on oil and natural gas revenues due to derivatives	$ 6,721	$ 25,437

Stock and Incentive Compensation. During the first quarter of 2010, we granted awards covering 248,383 shares of restricted stock. These awards were granted as retention incentive awards. The first quarter 2010 restricted stock awards had an estimated fair value as of the grant date of $10.6 million. Compensation expense will be recognized over the two and three year vesting periods, and during the first quarter of 2010, we recognized $1.2 million in additional compensation expense and capitalized $0.2 million for these awards. During the first three months of 2010, we recognized compensation expense of $2.5 million for all of our restricted stock, stock options and SAR grants and capitalized $0.5 million of compensation cost for oil and natural gas properties.

Insurance. We are self-insured for certain losses relating to workers' compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 for fiduciary liability to $1.0 million for 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 15 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 three months of 2010 and 2009, the total we received for all of these fees was $0.3 million and $0.3 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

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 – *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures--Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU is the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement will not have a significant impact on us due to it only requiring enhanced disclosures.

Results of Operations

Quarter Ended March 31, 2010 versus Quarter Ended March 31, 2009

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

	Quarter Ended March 31, 2010	Quarter Ended March 31, 2009	Percent Change
Total revenue	$ 206,550,000	$ 201,062,000	3 %
Net income (loss)	$ 36,153,000	$ (147,493,000)	125 %
Contract Drilling:			
Revenue	$ 60,854,000	$ 88,699,000	(31)%
Operating costs excluding depreciation	$ 40,900,000	$ 50,330,000	(19)%
Percentage of revenue from daywork contracts	98 %	100 %	(2)%
Average number of drilling rigs in use	50.9	52.8	(4)%
Average dayrate on daywork contracts	$ 14,127	$ 18,638	(24)%
Depreciation	$ 13,786,000	$ 12,619,000	9 %
Oil and Natural Gas:			
Revenue	$ 99,053,000	$ 88,904,000	11 %
Operating costs excluding depreciation, depletion, amortization and impairment	$ 25,034,000	$ 24,816,000	1 %
Average oil price (Bbl)	$ 67.33	$ 50.51	33 %
Average NGL price (Bbl)	$ 42.76	$ 18.69	129 %
Average natural gas price (Mcf)	$ 5.95	$ 5.44	9 %
Oil production (Bbl)	303,000	343,000	(12)%
NGL production (Bbl)	377,000	393,000	(4)%
Natural gas production (Mcf)	10,034,000	11,862,000	(15)%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.78	$ 2.32	(23)%
Depreciation, depletion and amortization	$ 25,336,000	$ 38,006,000	(33)%
Impairment of oil and natural gas properties	$ —	$ 281,241,000	NM
Mid-Stream Operations:			
Revenue	$ 41,135,000	$ 22,143,000	86 %
Operating costs excluding depreciation and amortization	$ 32,726,000	$ 20,677,000	58 %
Depreciation and amortization	$ 3,941,000	$ 4,061,000	(3)%
Gas gathered—MMBtu/day	180,117	192,320	(6)%
Gas processed—MMBtu/day	76,513	72,650	5 %
Gas liquids sold—gallons/day	253,707	218,762	16 %
General and administrative expense	$ 6,279,000	$ 6,089,000	3 %
Interest expense, net	$ —	$ 477,000	NM
Income tax expense (benefit)	$ 22,395,000	$ (89,761,000)	125 %
Average interest rate	6.1 %	4.0 %	53 %
Average long-term debt outstanding	$ 31,081,000	$ 195,774,000	(84)%

(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 $27.8 million or 31% in the first quarter of 2010 versus the first quarter of 2009 primarily due to a 24% lower average dayrate in the first quarter of 2010 compared to the first quarter of 2009 and to a lesser extent a 4% decrease in the average number of rigs in use during the first quarter of 2010 compared to the first quarter of 2009. Average drilling rig utilization decreased from 52.8 drilling rigs in the first quarter of 2009 to 50.9 drilling rigs in the first quarter of 2010. Commodity prices have improved in the first quarter of 2010 compared to the first quarter of 2009. While we experienced increased drilling activity and spending by our customers during the first quarter of 2010 compared to the fourth quarter of 2009, weak natural gas prices may limit further increases and could result in reduced activity through 2010.

Drilling operating costs decreased $9.4 million or 19% between the comparative first quarters of 2010 and 2009 primarily due to reductions in per day direct cost, indirect and workers' compensation expense and to a lesser extent a 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. As demand for our rigs begin to increase so will the competition for qualified labor. Contract drilling depreciation increased $1.2 million or 9% primarily due to capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas:

Oil and natural gas revenues increased $10.1 million or 11% in the first quarter of 2010 as compared to the first quarter of 2009 primarily due to an increase in average oil, NGL and natural gas prices slightly offset by a 13% decrease in equivalent production volumes. Average oil prices between the comparative quarters increased 33% to $67.33 per barrel, NGL prices increased 129% to $42.76 per barrel and natural gas prices increased 9% to $5.95 per Mcf. In the first quarter of 2010, as compared to the first quarter of 2009, oil production decreased 12%, NGL production decreased 4% and natural gas production decreased 15% due to the natural declines in production from wells as we slowed down our drilling activity and reserve replacement throughout most of 2009 due to low commodity prices. We began increasing drilling activity during the fourth quarter of 2009 and currently plan to continue to increase our activity throughout 2010.

Oil and natural gas operating costs increased $0.2 million or 1% between the comparative first quarters of 2010 and 2009 as reductions in lease operating expenses were offset by increased gross production taxes due to higher commodity prices between quarters. Lease operating expenses per Mcfe decreased 1% to $1.06.

Depreciation, depletion and amortization ("DD&A") decreased $12.7 million or 33% primarily due to a 23% decrease in our DD&A rate and a 13% decrease in equivalent production. The decrease in our DD&A rate in the first quarter of 2010 compared to the first quarter of 2009 resulted primarily from the $281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties in the first quarter of 2009 as a result of a decline in commodity prices. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities.

Mid-Stream:

Our mid-stream revenues were $19.0 million or 86% higher for the first quarter of 2010 as compared to the first quarter of 2009 primarily due to higher NGL and natural gas prices and higher NGL volumes processed and sold. The average price for NGLs sold increased 81% and the average price for natural gas sold increased 57%. Gas processing volumes per day increased 5% between the comparative quarters and NGLs sold per day increased 16% 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 2009. NGLs sold volumes per day increased due to both an increase in volumes processed and 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.

Operating costs increased $12.0 million or 58% in the first quarter of 2010 compared to the first quarter of 2009 primarily due to a 73% increase in prices paid for natural gas purchased. Depreciation and amortization decreased $0.1 million, or 3%, primarily due to decreased amortization on our intangible assets. For 2010, we anticipate an increase in well connections over 2009 due to anticipated drilling activity by operators in the areas of our existing gathering systems as well as adding an additional processing facility to accommodate the increased drilling activity of our oil and natural gas segment.

Other:

Other revenue of $5.5 million for the first three months of 2010 was primarily attributable to the sale of six mechanical drilling rigs.

Interest expense, net of capitalized interest, decreased $0.5 million between the comparative quarters. 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 53% higher and our average debt outstanding was 84% lower in the first quarter of 2010 as compared to the first quarter of 2009. Total interest incurred increased $0.3 million for the first quarter of 2010 and $0.2 million for the first quarter of 2009 due to interest rate swap settlements.

Income tax expense (benefit) changed from a benefit of $89.8 million in the first quarter of 2009 to an expense of $22.4 million in the first quarter of 2010 due to the non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of 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 was 38.3% and 37.8% for the first quarters of 2010 and 2009, respectively. The portion of our taxes reflected as a current income tax expense for the first quarter of 2010 was $2.2 million or 10% of the total income tax expense for the first quarter of 2010 as compared with zero of total income tax expense in the first quarter of 2009. Income taxes paid in the first quarter of 2010 were $2.4 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" and 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 three months 2010 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 $320,000 per month ($3.8 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 $96,000 per month ($1.2 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 $121,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow.

We use hedging transactions to reduce price volatility and manage price risks. Our decisions regarding the amount and prices at which we choose to hedge certain of our products is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty, and 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. Currently, we also have one basis swap that does not qualify as cash flow hedge. These financial derivatives 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.

Oil and Natural Gas Segment:

At March 31, 2010, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr'10 – Dec'10	Crude oil - collar	1,000 Bbl/day	$67.50 put & $81.53 call	WTI – NYMEX
Apr'10 – Dec'10	Crude oil – swap	1,500 Bbl/day	$61.36	WTI – NYMEX
Apr'10 – Dec'10	Natural gas – swap	15,000 MMBtu/day	$ 7.20	IF – NYMEX (HH)
Apr'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	$ 6.89	IF – Tenn Zone 0
Apr'10 – Dec'10	Natural gas – swap	30,000 MMBtu/day	$ 6.12	IF – CEGT
Apr'10 – Dec'10	Natural gas – swap	20,000 MMBtu/day	$ 5.67	IF – PEPL
Apr'10 – Dec'10	Natural gas – basis differential swap	10,000 MMBtu/day	($0.79)	PEPL – NYMEX
Jan'11 – Dec'11	Natural gas – swap	15,000 MMBtu/day	$ 5.56	IF – NYMEX (HH)
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 – NYMEX
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$ 5.62	IF – PEPL

At March 31, 2010, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 – NYMEX
Jan'11 – Dec'11	Natural gas – basis differential swap	15,000 MMBtu/day	($0.21)	CEGT – NYMEX
Jan'11 – Dec'11	Natural gas – basis differential swap	10,000 MMBtu/day	($0.225)	PEPL – NYMEX

After March 31, 2010, we entered into the following cash flow hedge:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
May'10–Dec'11	Liquids – swap (1)	644,406 Gal/mo	$0.97	OPIS – Conway

(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 three months of 2010, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by less than $0.1 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 March 31, 2010 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 March 31, 2010 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

For information regarding legal proceedings, see Item 3 of our Form 10-K for the fiscal year ended December 31, 2009. There have been no significant changes to what was disclosed in the Form 10-K.

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, 2009, 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, 2009.

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 March 31, 2010:

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
January 1, 2010 to January 31, 2010	21,054	$ 45.01	21,054	—
February 1, 2010 to February 28, 2010	—	—	—	—
March 1, 2010 to March 31, 2010	—	—	—	—
Total	21,054	$ 45.01	21,054	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the January 2010 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. Reserved and Removed

Not applicable.

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: May 4, 2010

By: /s/ Larry D. Pinkston
LARRY D. PINKSTON
Chief Executive Officer and Director

Date: May 4, 2010

By: /s/ David T. Merrill
DAVID T. MERRILL
Chief Financial Officer and
Treasurer