UNIT CORP
Form 10-Q
May 03, 2011
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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, 2011

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 [x]   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 25, 2011, 48,167,687 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 like 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 availability of third party services required to complete wells; the uncertainty related to declines and fluctuations in production volumes; the liquidity of our customers; the behavior of financial markets, including fluctuations in interest, 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; impact on us and the economy of recently enacted legislation; 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, legislative and competitive nature. These uncertainties may cause our actual future results to be materially different than those expressed in our forward-looking statements. Except as maybe required by law, we do not undertake to update our forward-looking statements.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2011	December 31, 2010
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,236	$ 1,359
Accounts receivable, net of allowance for doubtful accounts of $5,083 both at March 31, 2011 and at December 31, 2010	134,858	130,142
Materials and supplies	6,290	6,316
Current derivative assets (Note 10)	0	5,568
Current income tax receivable	19,316	25,211
Current deferred tax asset	19,757	13,537
Prepaid expenses and other	7,558	6,047
Total current assets	189,015	188,180
Property and equipment:		
Drilling equipment	1,313,374	1,273,861
Oil and natural gas properties on the full cost method:		
Proved properties	2,858,466	2,738,093
Undeveloped leasehold not being amortized	181,503	175,065
Gas gathering and processing equipment	208,610	199,564
Transportation equipment	33,266	31,688
Other	30,268	28,511
	4,625,487	4,446,782
Less accumulated depreciation, depletion, amortization and impairment	2,106,979	2,047,031
Net property and equipment	2,518,508	2,399,751
Goodwill	62,808	62,808
Other intangible assets, net	2,741	3,022
Non-current derivative assets (Note 10)	0	2,537
Other assets	12,972	12,942
Total assets	$ 2,786,044	$ 2,669,240

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	March 31, 2011	December 31, 2010
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 108,495	$ 89,885
Accrued liabilities (Note 5)	27,099	30,093
Contract advances	5,247	2,582
Current portion of derivative liabilities (Note 10)	25,558	14,446
Current portion of other long-term liabilities (Note 6)	9,875	10,122
Total current liabilities	176,274	147,128
Long-term debt (Note 6)	185,000	163,000
Long-term derivative liabilities (Note 10)	9,904	4,359
Other long-term liabilities (Note 6)	90,917	88,030
Deferred income taxes	579,085	556,106
Shareholders equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $.20 par value, 175,000,000 shares authorized, 48,169,566 and 47,910,431 shares issued, respectively	9,524	9,493
Capital in excess of par value	400,543	393,501
Accumulated other comprehensive loss	(20,704)	(6,851)
Retained earnings	1,355,501	1,314,474
Total shareholders equity	1,744,864	1,710,617
Total liabilities and shareholders equity	$ 2,786,044	$ 2,669,240

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Revenues:		
Contract drilling	$ 97,988	$ 60,854
Oil and natural gas	109,834	99,053
Gas gathering and processing	39,764	41,135
Other	(181)	5,508
Total revenues	247,405	206,550
Expenses:		
Contract drilling:		
Operating costs	52,844	40,900
Depreciation	17,297	13,786
Oil and natural gas:		
Operating costs	30,781	25,034
Depreciation, depletion and amortization	40,268	25,336
Gas gathering and processing:		
Operating costs	29,055	32,726
Depreciation and amortization	3,773	3,941
General and administrative	6,892	6,279
Interest, net	54	0
Total operating expenses	180,964	148,002
Income before income taxes	66,441	58,548
Income tax expense:		
Current	0	2,240
Deferred	25,414	20,155
Total income taxes	25,414	22,395
Net income	$ 41,027	$ 36,153
Net income per common share:		
Basic	$ 0.86	$ 0.77
Diluted	$ 0.86	$ 0.76

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 41,027	$ 36,153
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	61,577	43,313
Unrealized (gain) loss on derivatives	2,328	(1,148)
Deferred tax expense	25,414	20,155
(Gain) loss on disposition of assets	170	(5,435)
Stock compensation plans	3,286	3,316
Other	895	676
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(4,716)	(13,304)
Accounts payable	(15,952)	966
Material and supplies inventory	26	245
Accrued liabilities	101	(4,269)
Contract advances	2,665	(1,537)
Other net	4,384	536
Net cash provided by operating activities	121,205	79,667
INVESTING ACTIVITIES:		
Capital expenditures	(165,617)	(105,269)
Producing property and other acquisitions	(4,052)	(294)
Proceeds from disposition of assets	457	18,313
Other - net	0	324
Net cash used in investing activities	(169,212)	(86,926)
FINANCING ACTIVITIES:		
Borrowings under line of credit	88,800	19,100
Payments under line of credit	(66,800)	(19,100)
Proceeds from exercise of stock options	513	246
Book overdrafts	25,371	6,912
Net cash provided by financing activities	47,884	7,158
Net decrease in cash and cash equivalents	(123)	(101)
Cash and cash equivalents, beginning of period	1,359	1,140
Cash and cash equivalents, end of period	$ 1,236	$ 1,039

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(UNAUDITED)

	Three Months Ended March 31, 2011	2010
	(In thousands)	
Net income	$ 41,027	$ 36,153
Other comprehensive income, net of taxes:		
Change in value of derivative instruments used as cash flow hedges, net of tax of ($9,184) and $14,667	(14,827)	23,672
Reclassification - derivative settlements, Net of tax of ($127) and ($2,014)	(205)	(3,252)
Ineffective portion of derivatives, net of tax of $730 and ($417)	1,179	(674)
Comprehensive income	$ 27,174	$ 55,899

The accompanying notes are an integral part of these

condensed consolidated financial statements.

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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, as appropriate, one or more of its subsidiaries and affiliates, except as otherwise 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 24, 2011, for the year ended December 31, 2010.

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, 2011 and December 31, 2010;

Statements of Income for the three months ended March 31, 2011 and 2010;

Cash Flows for the three months ended March 31, 2011 and 2010; and

Statements of Comprehensive Income for the three months ended March 31, 2011 and 2010.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may 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, 2011 and 2010 are not necessarily indicative of the results to be realized for the full year in the case of 2011, or that we realized for the full year of 2010.

With respect to the unaudited financial information for the three month periods ended March 31, 2011 and 2010, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated May 3, 2011, 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 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.

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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. Under those rules, the maximum amount allowed as the carrying value of those properties is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves based on the unescalated 12-month average price on our oil, natural gas liquids (NGLs) and natural gas adjusted for any cash flow hedges, plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. In the event the unamortized cost of the amortized oil and natural gas properties 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.

At March 31, 2011, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down. However, if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods. Our qualifying cash flow hedges used in the ceiling test determination as of March 31, 2011, consisted of swaps covering 29.4 Bcfe in 2011, 17.6 Bcfe in 2012 and 2.2 Bcfe in 2013. The effect of those hedges on the March 31, 2011 ceiling test was a $40.9 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 10 of the Notes to our Condensed Consolidated Financial Statements.

NOTE 3 ACQUISITIONS

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post close adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. These properties focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition from unaffiliated parties of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

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NOTE 4 - EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended March 31, 2011:			
Basic earnings per common share	$ 41,027	47,584	$ 0.86
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	0	321	0
Diluted earnings per common share	$ 41,027	47,905	$ 0.86
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 SARs	0	565	(0.01)
Diluted earnings per common share	$ 36,153	47,686	$ 0.76

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,	
	2011	2010
Stock options and SARs	73,500	132,165
Average Exercise Price	$ 64.43	$ 59.87

NOTE 5 ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Employee costs	$ $9,520	$ $16,499
Lease operating expense accrual	6,064	6,214
Taxes	3,486	1,310
Hedge settlements	2,475	1,634
Other	5,554	4,436
Total accrued liabilities	$ 27,099	$ 30,093

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NOTE 6 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, 2011	December 31, 2010
	(In thousands)	
Revolving credit facility with average interest rates, including the effect of hedging, of 2.8% at March 31, 2011 and 3.5% at December 31, 2010	$ 185,000	$ 163,000
Less current portion	0	0
Total long-term debt	$ 185,000	$ 163,000

Our credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we from time to time elect. As of March 31, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement.

The lenders aggregate commitment is limited to the lesser of the amount 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 segment. The April 1, 2011 redetermination increased the borrowing base to $600.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base 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 for the applicable period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each period, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is 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, 2011, all of our $185.0 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.

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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 2011, we were in compliance with our credit facility s covenants.

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, 2011 approximates its fair value.

At March 31, 2011, the carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligations (ARO) liability	$ 71,338	$ 69,265
Workers compensation	17,666	17,566
Separation benefit plans	5,953	5,690
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,572	2,368
	100,792	98,152
Less current portion	9,875	10,122
Total other long-term liabilities	$ 90,917	$ 88,030

The estimated annual payments due under the terms of our debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2011 (and through 2016) are $9.9 million, $199.6 million, $3.3 million, $2.7 million and $2.1 million, respectively.

NOTE 7 ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are 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 liability 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. All of our AROs relate to the plugging costs associated with our oil and gas wells.

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

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
ARO liability, January 1:	$ 69,265	$ 56,404
Accretion of discount	874	687
Liability incurred	1,559	472
Liability settled	(359)	(270)
Revision of estimates	(1)	49
ARO liability, March 31:	71,338	57,342
Less current portion	1,836	1,632
Total long-term plugging liability	$ 69,502	$ 55,710

NOTE 8 - 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 was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

NOTE 9 STOCK-BASED COMPENSATION

For the three months ended March 31, 2011 and 2010, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.3 million and $2.5 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.6 million and $0.5 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $0.9 million each period. The remaining unrecognized compensation cost related to unvested awards at March 31, 2011 is approximately $16.3 million of which $3.1 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

We did not grant any stock options or SARs during either of the three month periods ending March 31, 2011 and 2010.

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

	Three Months Ended March 31, 2011	2010
Shares granted	192,581	248,383
Estimated fair value (in millions)	$ 10.0	$ 10.6
Percentage of shares granted expected to be distributed	93%	93%

The restricted stock awards granted during the first three months of 2011 will be recognized over a three year vesting period except for certain designated executive officers. For grants to those executive offers covering 66,869 shares of the total granted, 70% will vest in equal one-third annual increments, the other 30% of the shares awarded will cliff vest in the first quarter of 2014, but only if certain performance criteria are met which could result in fewer or additional shares vesting. These awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first quarter of 2011 by an aggregate of $0.5 million.

NOTE 10 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 our credit facility. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. As of March 31, 2011, 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 those interest rate swaps:

Remaining Term		Amount	Fixed Rate	Floating Rate
April 2011	May 2012	$ 15,000,000	4.53%	3 month LIBOR
April 2011	May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of March 31, 2011, our derivative transactions consisted of the following types of swaps:

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

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.

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Oil and Natural Gas Segment:

At March 31, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr 11 Dec 11	Crude oil swap	4,000 Bbl/day	$84.28	WTI NYMEX
Jan 12 Dec 12	Crude oil swap	3,000 Bbl/day	$90.92	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	1,000 Bbl/day	$101.08	WTI NYMEX
Apr 11 Dec 11	Natural gas swap	10,000 MMBtu/day	$4.43	CEGT
Apr 11 Dec 11	Natural gas swap	70,000 MMBtu/day	$4.87	IF NYMEX (HH)
Apr 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	$5.06	IF NYMEX (HH)
Jan 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Apr 11 Dec 11	Liquids swap (1)	644,406 Gal/mo	$0.96	OPIS Conway

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

At March 31, 2011, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Apr 11 Dec 11	Natural gas basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 NYMEX
Apr 11 Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.21)	CEGT NYMEX
Apr 11 Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.23)	PEPL NYMEX

After March 31, 2011, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
Jan 12 Dec 12	Crude oil swap	1,000 Bbl/day	$107.31	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	500 Bbl/day	$104.40	WTI NYMEX

The following tables present the fair values and locations of the derivative transactions recorded in our balance sheets:

	Balance Sheet Location	Derivative Assets Fair Value March 31, 2011	December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 0	$ 5,091
Long-term	Non-current derivative assets	0	2,537
Total derivatives designated as hedging instruments		0	7,628

Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	0	477
Total derivatives not designated as hedging instruments		0	477
Total derivative assets		$ 0	$ 8,105

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	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2011	December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 1,167	$ 1,139
Long-term	Long-term derivative liabilities	194	475
Commodity derivatives:			
Current	Current portion of derivative liabilities	24,308	13,166
Long-term	Long-term derivative liabilities	9,710	3,884
Total derivatives designated as hedging instruments		35,379	18,664
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	83	141
Total derivatives not designated as hedging instruments		83	141
Total derivative liabilities		$ 35,462	$ 18,805

If a legal right of set-off exists, we net the value of the derivative transactions 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, 2011 and 2010, we had a loss of $20.7 million and a gain of $24.2 million, net of tax, respectively, in accumulated OCI.

Based on market prices at March 31, 2011, we expect to transfer a loss of approximately $15.9 million, net of tax, 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, 2011 are expected to mature by May 2012 and December 2013, 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 Income (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) 2011	2010
	(In thousands)	
Interest rate swaps	$ (840)	$ (1,247)
Commodity derivatives	(19,864)	25,451
Total	$ (20,704)	$ 24,204

(1) Net of taxes.

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Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (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]	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 635	$ 5,573	$ (1,909)	$ 1,091
Interest rate swaps	Interest, net	(303)	(307)	0	0
	Total	$ 332	$ 5,266	$ (1,909)	$ 1,091

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

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (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	
		2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (601)	$ 57
Total		$ (601)	$ 57

NOTE 11 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.

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The following tables set forth our recurring fair value measurements:

	March 31, 2011		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Interest rate swaps	$ 0	$ (1,361)	$ (1,361)
Commodity derivatives	$ (43,469)	$ 9,368	$ (34,101)

	December 31, 2010		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Interest rate swaps	$ 0	$ (1,614)	$ (1,614)
Commodity derivatives	$ (19,954)	$ 10,868	$ (9,086)

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, natural gas liquids and basis swaps are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

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

	Net Derivatives			
	For the Three Months Ended March 31, 2011		For the Three Months Ended March 31, 2010	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,614)	$ 10,868	$ (1,948)	$ 19,948
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	(303)	4,305	(307)	9,074
Included in other comprehensive income (loss)	253	(1,765)	(71)	30,343
Settlements	303	(4,040)	307	(7,926)
End of period	$ (1,361)	$ 9,368	$ (2,019)	$ 51,439
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ 0	$ 265	$ 0	$ 1,148

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

Based on our valuation at March 31, 2011, we determined that the non-performance risk with regard to our counterparties was immaterial.

NOTE 12 - 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.

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We evaluate each segment s performance based on its operating income, 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, 2011	2010
	(In thousands)	
Revenues:		
Contract drilling	$ 112,508	$ 67,501
Elimination of inter-segment revenue	(14,520)	(6,647)
Contract drilling net of inter-segment revenue	97,988	60,854
Oil and natural gas	109,834	99,053
Gas gathering and processing	57,008	53,734
Elimination of inter-segment revenue	(17,244)	(12,599)
Gas gathering and processing net of inter-segment revenue	39,764	41,135
Other	(181)	5,508
Total revenues	$ 247,405	$ 206,550
Operating income [(1)]:		
Contract drilling	$ 27,847	$ 6,168
Oil and natural gas	38,785	48,683
Gas gathering and processing	6,936	4,468
Total operating income	73,568	59,319
General and administrative expense	(6,892)	(6,279)
Interest expense, net	(54)	0
Other	(181)	5,508
Income before income taxes	$ 66,441	$ 58,548

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

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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, 2011, and the related condensed consolidated statements of income and comprehensive income for the three-month periods ended March 31, 2011 and 2010 and the condensed consolidated statements of cash flows for the three-month periods ended March 31, 2011 and 2010. 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, 2010, 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 24, 2011, 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, 2010, 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 3, 2011

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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 with the unaudited condensed consolidated financial statements and related notes included in this quarterly 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.
- *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 quarterly report, the success of our consolidated business, as well as that of each of our three operating segments depends, to a large extent, on: the prices we receive 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. Although all of our current 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 have an impact on 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.

Our 2011 consolidated capital budget forecasts a 16% increase over our 2010 capital expenditures, excluding acquisitions. Our oil and natural gas segment s capital budget is $415.0 million, a 12% increase over 2010, excluding acquisitions. We plan to continue our aggressive exploration program in 2011, which is focused on oil or NGL rich prospects, with a significant portion of our wells being horizontal. Our contract drilling segment s capital budget is $143.0 million, a 20% increase over 2010. Our 2011 plans for this segment include the construction of five new 1,500 horsepower diesel-electric drilling rigs (one of which has already been placed into service during the first quarter), as well as refurbishing and upgrading several of our existing drilling rigs so that those drilling rigs can be used to drill horizontal wells. Our mid-stream segment s capital budget is $47.0 million, a 58% increase over 2010. The increase is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as committing to build a 16-mile, 16 pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day and is anticipated to be completed by mid-2011.

In developing our initial overall operating budget for 2011, we used average oil and natural gas prices of $82.00 per Bbl and $4.60 per Mcf. Our 2011 operating budget will be funded using internally generated cash flow and borrowings under our credit facility.

Executive Summary

Contract Drilling

Our utilization rate for the first quarter 2011 was 58%, compared to 59% and 40% for the fourth quarter of 2010 and the first quarter of 2010, respectively.

Dayrates for the first quarter of 2011 averaged $17,704, an increase of 7% from the fourth quarter of 2010 and an increase of 25% from the first quarter of 2010. These increases were due primarily to increased demand for drilling rigs in the 1,000 to 1,500 horse power range which are used in horizontal drilling and provide for higher rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the first quarter of 2011 increased 1% from the fourth quarter of 2010 and 126% from the first quarter of 2010. The increase was primarily due to increases in dayrates and utilization over the first quarter 2010.

Operating cost per day for the first quarter of 2011 increased 1% from the fourth quarter of 2010 and decreased 6% from the first quarter of 2010. The increase over fourth quarter 2010 is primarily due to increases in indirect expenses because of increases in personnel cost. The decrease over first quarter 2010 was primarily due to decreased per day indirect cost and fixed cost spread over more days due to increased utilization.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. With the current weakened demand and prices for natural gas, operators are focusing on drilling for oil and NGLs. Approximately 80% of our drilling rigs working today are drilling for oil or NGLs of which approximately 99% are drilling horizontal or directional wells.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. One of these new drilling rigs has been completed and was delivered and placed in service in the Bakken shale in March 2011. The second drilling rig began mobilizing to its first location in April. The remaining three drilling rigs are expected to be completed late in the third quarter of 2011. On completion of the additional four drilling rigs, we will have 126 drilling rigs in our fleet. Each of these five new drilling rigs will initially be dedicated to a two-year drilling contract.

Our anticipated 2011 capital expenditures for this segment are $143.0 million.

As of March 31, 2011, we had 41 long-term drilling contracts with original terms ranging from six months to two years. Thirty-two of these contracts are up for renewal during 2011 and nine are up for renewal in 2012 and beyond. These contracts include two of the five term contracts for the new drilling rigs discussed above. Of the 32 contracts renewing in 2011; 13 renew during the second quarter, nine during the third quarter and ten during the fourth quarter. Term contracts may contain a fixed rate for the duration of the contract or provide for the rate adjustments within a specific range from the existing rate.

Oil and Natural Gas

During the second quarter of 2010 we completed an acquisition of oil and natural gas properties from certain unaffiliated parties. The properties were purchased for approximately $73.7 million in cash. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. These properties are focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. Proved developed producing net reserves associated with the 10 acquired producing wells is approximately 762,000 barrels of oil equivalent consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

First quarter 2011 production was 2,739,000 barrels of oil equivalent (Boe) per day, a 2% increase over the fourth quarter of 2010 and a 16% increase over the first quarter of 2010. The increase in production is primarily due to new wells being completed and coming online and, to a lesser extent, production associated with the acquisition discussed above. Our production in 2010 was hindered by delays in securing third party fracture stimulation services and delays associated with connecting wells to gathering systems. In addition, our production was curtailed because of the unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production.

First quarter 2011 oil and natural gas revenues decreased 4% from the fourth quarter of 2010 and increased 11% from the first quarter of 2010.

Our oil prices for the first quarter of 2011 increased 14% from the fourth quarter of 2010 and 25% from the first quarter of 2010. NGL and natural gas prices for the first quarter of 2011 decreased 1% and 21%, respectively, compared to fourth quarter 2010 and decreased 7% and 28%, respectively, compared to the first quarter of 2010.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 7% from the fourth quarter of 2010 and increased 7% from the first quarter of 2010. The decrease was primarily attributable to decreases in natural gas and liquids prices received including the effect of hedging and to a lesser extent from increases in operating expenses. The increase from the first quarter 2010 was primarily attributable to increases in production and oil prices partially offset by increased lease operating expense and gross production taxes.

Operating cost per Boe produced for the first quarter of 2011 increased 3% from the fourth quarter of 2010 and increased 6% from the first quarter of 2010. The increases were primarily due to the increase in lease operating expense (LOE) and an increase in production taxes. Production taxes increased due to commodity price increases between the periods and increased oil and NGL production.

For 2011, we currently have hedged approximately 65% of our anticipated daily oil production, approximately 64% of our anticipated natural gas production and approximately 10% of our anticipated natural gas liquids production (percentages based on our first quarter 2011 production).

Currently for 2012 we have hedged 4,000 Bbls per day of oil production and 30,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $95.01 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.48. The average basis differential for the applicable swaps is ($0.28).

Currently for 2013 we have hedged 1,500 Bbls per day of oil production. The oil production is hedged under swap contracts at an average price of $102.18 per barrel.

During the first quarter of 2011, we drilled 34 gross wells (17.19 net wells). Our 2011 production guidance is approximately 11.0 to 11.3 MMBoe, although actual results will continue to be subject to a number of factors including the timing of third party services. For 2011, we plan to participate in the drilling of 180 wells and the level of our capital expenditures is $415.0 million.

Mid-Stream

First quarter 2011 liquids sold per day increased 13% from the fourth quarter of 2010 and increased 29% from the first quarter of 2010. The increases resulted from upgrades and expansions to existing plants and the connection of new wells. For the first quarter of 2011, gas processed per day increased 1% from the fourth quarter of 2010 and 13% from the first quarter of 2010. In 2010, we upgraded several of our existing processing facilities and added processing plants which was the primary reason for increased volumes. For the first quarter of 2011, gas gathered per day decreased 1% from the fourth quarter of 2010 due to weather related issues experienced in the first quarter and increased 3% from the first quarter of 2010 primarily from the 52 well connects throughout 2010.

NGL prices in the first quarter of 2011 remained essentially unchanged from the price received in the fourth quarter of 2010 and decreased 1% from the price received in the first quarter of 2010. 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.

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Direct profit (mid-stream revenues less mid-stream operating expense) for the first quarter of 2011 increased 9% from the fourth quarter of 2010 and increased 27% from the first quarter of 2010. The increases resulted primarily from increased liquids sold and gas processed volumes. Effective April 1, 2011, we had a change in arrangements with customers of one of our processing plants whereby the contracts changed from percent of index to percent of proceeds which could result in lower direct profit of up to $1.2 million per month based on current frac spreads.

Total operating cost for our mid-stream segment for the first quarter of 2011 decreased 2% from the fourth quarter of 2010 primarily due to the decrease in gas purchased and decreased 11% from the first quarter of 2010 due primarily to the decrease in price paid for the purchase of natural gas.

During the fourth quarter of 2010, we completed the installation and start up of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. With the addition of this new processing plant, the total processing capacity at our Hemphill facility has increased to approximately 100.0 MMcf per day. In connection with our Appalachian operations, we recently started construction of a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day. We anticipate this pipeline will be operational by mid-2011. We have signed an agreement to transport gas on this system for an unaffiliated party. In addition to the Preston County pipeline, we recently signed a contract to build a 12-mile pipeline system and compressor station in Tioga and Potter Counties, Pennsylvania. This system will deliver gas to Dominion Transmission pipeline and is scheduled to be completed in the fourth quarter of this year.

Our anticipated capital expenditures for 2011 are $47.0 million.

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 oil, NGL and natural gas production; and
- the margins we obtain from our natural gas gathering and processing contracts.

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The following is a summary of certain financial information as of March 31, 2011 and 2010 and for the three months ended March 31, 2011 and 2010:

	March 31, 2011	March 31, 2010	% Change [1]
	(In thousands except percentages)		
Working capital	$ 12,741	$ 56,070	(77)%
Long-term debt	$ 185,000	$ 30,000	NM
Shareholders equity	$ 1,744,864	$ 1,628,483	7%
Ratio of long-term debt to total capitalization	10%	2%	NM
Net income	$ 41,027	$ 36,153	13%
Net cash provided by operating activities	$ 121,205	$ 79,667	52%
Net cash used in investing activities	$ (169,212)	$ (86,926)	95%
Net cash provided by financing activities	$ 47,884	$ 7,158	NM

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

The following table summarizes certain operating information:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	70	50.9	38%
Total number of drilling rigs owned at the end of the period	122	125	(2)%
Average dayrate	$ 17,704	$ 14,127	25%
Oil and Natural Gas:			
Oil production (MBbls)	556	303	83%
Natural gas liquids production (MBbls)	478	377	27%
Natural gas production (MMcf)	10,231	10,034	2%
Average oil price per barrel received	$ 84.33	$ 67.33	25%
Average oil price per barrel received excluding hedges	$ 90.78	$ 75.70	20%
Average NGL price per barrel received	$ 39.61	$ 42.76	(7)%
Average NGL price per barrel received excluding hedges	$ 40.36	$ 42.76	(6)%
Average natural gas price per mcf received	$ 4.28	$ 5.95	(28)%
Average natural gas price per mcf received excluding hedges	$ 3.85	$ 5.14	(25)%
Mid-Stream:			
Gas gathered MMBtu/day	185,730	180,117	3%
Gas processed MMBtu/day	86,445	76,513	13%
Gas liquids sold gallons/day	328,333	253,707	29%
Number of natural gas gathering systems	34	33	3%
Number of processing plants	10	8	25%

At March 31, 2011, we had unrestricted cash totaling $1.2 million and we had borrowed $185.0 million of the $325.0 million we had elected to have currently available under our credit facility. Our credit facility is used for working capital and capital expenditures.

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 $12.7 million and $56.1 million as of March 31, 2011 and 2010, respectively. The effect of our hedging activity decreased working capital by $15.9 million as of March 31, 2011 and increased working capital by $24.3 million as of March 31, 2010.

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Contract Drilling

Many factors influence the number of drilling rigs we are able to work as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs and natural gas, availability, the cost of labor to run our drilling rigs and our ability to supply the equipment needed.

As activity has increased over last year s levels, competition to keep qualified labor has likewise increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all our divisions.

Over the past year as more of our customers shift to drilling horizontal wells, demand for drilling rigs in the 1,000 to 1,500 horsepower range has increased as drilling rigs within that horsepower range are ideally suited for horizontal drilling. The level of future demand for and the availability of drilling rigs to meet this demand will have an impact on our future dayrates. For the first quarter of 2011, our average dayrate was $17,704 per day compared to $14,127 per day for the first quarter of 2010. Our average number of drilling rigs used in the first quarter of 2011 was 70.0 drilling rigs (58%) compared with 50.9 drilling rigs (40%) in the first quarter of 2010. Based on the average utilization of our drilling rigs during the first quarter of 2011, a $100 per day change in dayrates has a $7,000 per day ($2.6 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our oil and natural gas segment. Depending on the timing of the services, some of the drilling services we perform on our properties are deemed to be associated with the acquisition of an ownership interest in the property. Accordingly, revenues and expenses for those drilling services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $14.5 million and $6.6 million for the three months of 2011 and 2010, respectively, from our contract drilling segment and eliminated the associated operating expense of $9.5 million and $6.2 million during the three months of 2011 and 2010, respectively, yielding $5.0 million and $0.4 million during the three months of 2011 and 2010, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Impact of Prices for Our Oil, NGLs and Natural Gas

Any significant change in oil or natural gas prices has a material effect on our revenues, cash flow and the value of our oil, liquids and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first three months of 2011 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 $326,000 per month ($3.9 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 2011 was $4.28 compared to $5.95 for the first three months of 2010. Based on our first three months of 2011 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $177,000 per month ($2.1 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 $152,000 per month ($1.8 million annualized) change in our pre-tax operating cash flow. In the first three months of 2011, our average oil price per barrel received, including the effect of hedging, was $84.33 compared with an average oil price, including the effect of hedging, of $67.33 in the first three months of 2010 and our first three months of 2011 average NGLs price per barrel received was $39.61 compared with an average NGL price per barrel of $42.76 in the first three months of 2010.

Because commodity prices have an 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 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.

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Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms and gatherers under contracts with terms generally ranging anywhere from one month to five years. Our oil production is sold to independent marketing firms generally in six month increments.

Mid-Stream Operations

Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries. Superior is engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, 10 processing plants, 34 gathering systems and 867 miles of pipeline. Superior operates in Oklahoma, Texas, Kansas, Pennsylvania and West Virginia 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 2011 and 2010, our mid-stream operations purchased $16.1 million and $11.6 million, respectively, of our oil and natural gas segment s production and provided gathering and transportation services to the oil and natural gas segment of $1.1 million and $1.0 million, respectively. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our condensed consolidated financial statements.

Our mid-stream segment gathered an average of 185,730 MMBtu per day in the first quarter of 2011 compared to 180,117 MMBtu per day in the first quarter of 2010. Processed volumes were 86,445 MMBtu per day in the first quarter of 2011 compared to 76,513 MMBtu per day in the first quarter of 2010. The amount of NGLs we sold was 328,333 gallons per day in the first quarter of 2011 compared to 253,707 gallons per day in the first quarter of 2010. Gas gathering volumes per day in the first three months of 2011 increased 3% compared to the first three months of 2010 primarily from the 52 wells connected to our systems throughout 2010. Processed volumes increased 13% over the comparative three months and NGLs sold also increased 29% over the comparative period primarily due to the addition of wells connected, recent upgrades to several of our processing systems and the doubling in size of our Hemphill facility in the Texas Panhandle.

Our Credit Facility

Our credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we from time to time elect. As of March 31, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement. The average interest rate for both the first three months of 2011 and the first three months of 2010, which includes the effect of our two interest rate swaps, was 2.8% and 6.1%, respectively. At March 31, 2011 and April 25, 2011, borrowings were $185.0 million and $210.1 million, respectively.

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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	8.75%
BNP Paribas	8.75%
Crédit Agricole Corporate and Investment Bank	8.75%
	100.00%

The lenders aggregate commitment is limited to the lesser of the amount 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 segment. The April 1, 2011 redetermination increased the borrowing base to $600.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base 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 for the applicable period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each period, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is 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, 2011, all of our $185.0 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, 2011, we were in compliance with the credit facility s covenants.

We are in the process of re-negotiating our credit facility to extend our maturity date past May 24, 2012.

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We entered into the following interest rate swaps to manage our exposure to possible future interest rate increases under the credit facility. 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:

Remaining Term			Amount	Fixed Rate	Floating Rate
April 2011	May 2012	$	15,000,000	4.53%	3 month LIBOR
April 2011	May 2012	$	15,000,000	4.16%	3 month LIBOR

Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. During the first half of 2010, we sold eight of our idle mechanical drilling rigs to an unaffiliated party. These drilling rigs ranged in horse power from 800 to 1,000. Proceeds from this sale were $23.9 million resulting in a gain of $5.7 million which we recorded in the first quarter of 2010. The proceeds were used to refurbish and upgrade additional drilling rigs in our fleet allowing those drilling 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.

In September 2010, we entered into a contract with an unaffiliated party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction was closed in October and resulted in a gain of $3.5 million.

At the end of 2010, we signed contracts with two year terms for each of the five new 1,500 horse power drilling rigs which will be deployed in the Bakken play. All five of those drilling rigs are or will be built by us. One of the drilling rigs was delivered during the first quarter of 2011. One will be delivered during the second quarter and the remaining three during the third quarter of 2011.

Our anticipated 2011 capital expenditures for this segment are $143.0 million. At March 31, 2011, we had commitments to purchase approximately $10.8 million for drill pipe, top drives and related equipment over the next twelve months. We have spent $42.7 million for capital expenditures during the first three months of 2011 compared to $39.8 million in the first three months of 2010.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures for this segment 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 34 gross wells (17.19 net wells) in the first quarter of 2011 compared to 27 gross wells (12.16 net wells) in the first quarter of 2010. Total capital expenditures for the first three months of 2011 by this segment, excluding a $1.2 million ARO liability, and $4.1 million for acquisitions, totaled $121.6 million. Currently we plan to participate in drilling approximately 180 gross wells in 2011 and estimate our total capital expenditures (excluding acquisitions) for this segment will be approximately $415.0 million. Whether we are able to drill the full number of wells planned is dependent on a number of factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs and natural gas, demand for oil, NGLs and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners.

In June 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties. The properties were purchased for approximately $73.7 million in cash after giving effect to certain post-closing adjustments. After these adjustments, the acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. These properties focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

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Also during the second quarter of 2010, we completed an acquisition of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million from an unaffiliated party.

Mid-Stream Acquisitions and Capital Expenditures. During the fourth quarter of 2010, we completed the installation and start up of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. With the addition of this new processing plant, the total processing capacity at our Hemphill facility increased to approximately 100.0 MMcf per day.

In connection with our Appalachian operations, we recently committed to build a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day. Construction began during the first quarter of 2011 with the facility anticipated to be operational by mid-2011. We have signed an agreement to transport gas on this system for an unaffiliated party.

During the first quarter of 2011, our mid-stream segment incurred $9.0 million in capital expenditures as compared to $6.9 million in the first quarter of 2010. For 2011, we have budgeted capital expenditures of approximately $47.0 million.

Contractual Commitments

At March 31, 2011, we had certain contractual obligations including the following:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank debt (1)	$ 191,533	$ 5,691	$ 185,842	$ 0	$ 0
Operating leases (2)	5,438	1,655	2,696	1,087	0
Drill pipe, drilling components and equipment purchases (3)	10,844	10,844	0	0	0
Total contractual obligations	$ 207,815	$ 18,190	$ 188,538	$ 1,087	$ 0

(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, 2011 interest rate of 2.8% which includes the effect of our interest rate swaps.

(2) We lease office space or yards in Beaver, Elk City, Oklahoma City and Tulsa, Oklahoma; Canadian and Houston, Texas; Denver and Englewood, 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) We have committed to purchase approximately $10.8 million of new drilling rig components, drill pipe, drill collars and related equipment over the next twelve months.

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At March 31, 2011, 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)	$ 2,572	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 5,953	$ 135	Unknown	Unknown	Unknown
Derivative liabilities interest rate swaps	$ 1,361	$ 1,167	$ 194	$ 0	$ 0
Derivative liabilities commodity hedges	$ 34,101	$ 24,391	$ 9,710	$ 0	$ 0
Asset retirement liability (3)	$ 71,338	$ 1,836	$ 14,843	$ 3,657	$ 51,002
Gas balancing liability (4)	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ 0	Unknown	Unknown	Unknown	Unknown
Workers compensation liability (6)	$ 17,666	$ 7,904	$ 3,058	$ 1,098	$ 5,606

(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 Sheets, 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 certain 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 record 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. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $22,000 in 2010, $1,000 in 2009. There have been no re-purchases in 2011 through the first quarter.

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(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 rate payable under our credit facility as well as the prices to be received for a portion of our 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, 2011, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. Our March 31, 2011 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	$ (713)
April 2010	May 2012	$ 15,000	4.16%	3 month LIBOR	(648)
					$ (1,361)

Because of these interest rate swaps, our interest expense increased by $0.3 million for each of the three months ended March 31, 2011 and 2010. A loss of $0.8 million, net of tax, is reflected in accumulated OCI as of March 31, 2011.

Commodity Hedges. Our commodity hedging is intended to reduce our exposer to 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 2011 average daily production, as of March 31, 2011, the approximated percentages of our production that we have hedged are as follows:

Oil and Natural Gas Segment:

	April December 2011	January December 2012	January December 2013
Daily oil production	65%	49%	16%
Daily natural gas production	64%	24%	0%
Natural gas liquids production	10%	0%	0%

With respect to the commodities subject to our hedges, 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 price movements above the hedged prices.

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The use of derivative transactions carries with it the risk that the counterparties will not be able to meet their financial obligations under the transactions. Based on our evaluation at March 31, 2011, we determined that there was no material risk of non-performance by our counterparties. At March 31, 2011, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2011 (In millions)
Bank of Montreal	$ (1.3)
Bank of America, N.A.	(2.4)
Crédit Agricole Corporate and Investment Bank, London Branch	(15.6)
Comerica Bank	(9.7)
BBVA Compass Bank	(3.9)
Barclays Capital	(0.9)
BNP Paribas	(0.3)
Total assets (liabilities)	$ (34.1)

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our consolidated balance sheets. At March 31, 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of $24.4 million and $9.7 million, respectively. 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.

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, 2011, we had a loss of $19.9 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at March 31, 2011, we expect to transfer to earnings a loss of approximately $15.9 million, net of tax, of the loss 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, 2011 are expected to mature by May 2012 and December 2013, 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 consolidated statements of income 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 at March 31:

	2011	2010
	(In thousands)	
Increases (decreases) in:		
Oil and natural gas revenue:		
Realized gains (losses) on oil and natural gas derivatives	$ 453	$ 5,573
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(1,909)	1,091
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(419)	57
Total increase on oil and natural gas revenues due to derivatives	$ (1,875)	$ 6,721

Stock and Incentive Compensation

During the first three months of 2011, we granted awards covering 192,581 shares of restricted stock. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $10.0 million. Compensation expense will be recognized over their three year vesting periods, and during the first three months of 2011, we recognized $0.4 million in additional compensation expense and capitalized $0.1 million for these awards. During the first three months of 2011, we recognized compensation expense of $2.3 million for all of our restricted stock, stock options and SAR grants and capitalized $0.6 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 to $1.0 million. 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 16 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 2011 and 2010, the total we received for all of these fees was $0.6 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 was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

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Results of Operations

Quarter Ended March 31, 2011 versus Quarter Ended March 31, 2010

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

	Quarter Ended March 31,		Percent
	2011	2010	Change
Total revenue	$ 247,405,000	$ 206,550,000	20 %
Net income	$ 41,027,000	$ 36,153,000	13 %
Contract Drilling:			
Revenue	$ 97,988,000	$ 60,854,000	61 %
Operating costs excluding depreciation	$ 52,844,000	$ 40,900,000	29 %
Percentage of revenue from daywork contracts	100%	98%	2 %
Average number of drilling rigs in use	70.0	50.9	38 %
Average dayrate on daywork contracts	$ 17,704	$ 14,127	25 %
Depreciation	$ 17,297,000	$ 13,786,000	25 %
Oil and Natural Gas:			
Revenue	$ 109,834,000	$ 99,053,000	11 %
Operating costs excluding depreciation, depletion and amortization	$ 30,781,000	$ 25,034,000	23 %
Average oil price (Bbl)	$ 84.33	$ 67.33	25 %
Average NGL price (Bbl)	$ 39.61	$ 42.76	(7)%
Average natural gas price (Mcf)	$ 4.28	$ 5.95	(28)%
Oil production (Bbl)	556,000	303,000	83 %
NGL production (Bbl)	478,000	377,000	27 %
Natural gas production (Mcf)	10,231,000	10,034,000	2 %
Depreciation, depletion and amortization rate (Boe)	$ 14.58	$ 10.68	37 %
Depreciation, depletion and amortization	$ 40,268,000	$ 25,336,000	59 %
Mid-Stream Operations:			
Revenue	$ 39,764,000	$ 41,135,000	(3)%
Operating costs excluding depreciation and amortization	$ 29,055,000	$ 32,726,000	(11)%
Depreciation and amortization	$ 3,773,000	$ 3,941,000	(4)%
Gas gathered MMBtu/day	185,730	180,117	3 %
Gas processed MMBtu/day	86,445	76,513	13 %
Gas liquids sold gallons/day	328,333	253,707	29 %
General and administrative expense	$ 6,892,000	$ 6,279,000	10 %
Interest expense, net	$ 54,000	$ 0	NM
Income tax expense	$ 25,414,000	$ 22,395,000	13 %
Average interest rate	2.8%	6.1%	(54)%
Average long-term debt outstanding	$ 175,282,000	$ 31,081,000	NM

(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 increased $37.1 million or 61% in the first quarter of 2011 versus the first quarter of 2010 primarily due to a 38% increase in the average number of drilling rigs in use during the first quarter of 2011 compared to the first quarter of 2010 and a 25% higher average dayrate in the first quarter of 2011 compared to the first quarter of 2010. Average drilling rig utilization increased from 50.9 drilling rigs in the first quarter of 2010 to 70.0 drilling rigs in the first quarter of 2011. Oil prices improved in the first quarter of 2011 compared to the first quarter of 2010, creating increased demand for drilling rigs.

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Drilling operating costs increased $11.9 million or 29% between the comparative first quarters of 2011 and 2010 primarily due to increased utilization and increased indirect cost due to higher personnel cost. Due to an increase in activity over last year s levels, competition to keep qualified labor has increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all divisions. Contract drilling depreciation increased $3.5 million or 25% primarily due to capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $10.8 million or 11% in the first quarter of 2011 as compared to the first quarter of 2010 primarily due to an increase in equivalent production volumes of 16% and an increase in oil prices somewhat offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative quarters increased 25% to $84.33 per barrel, NGL prices decreased 7% to $39.61 per barrel and natural gas prices decreased 28% to $4.28 per Mcf. In the first quarter of 2011, as compared to the first quarter of 2010, oil production increased 83%, NGL production increased 27% and natural gas production increased 2%. Production for first quarter 2010 was negatively impacted by an unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production and production growth was hampered by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $5.7 million or 23% between the comparative first quarters of 2011 and 2010 due to increases in lease operating expenses due to increased workover expense and higher saltwater disposal fees and higher gross production taxes due to higher oil prices and revenue from increased production between quarters. Lease operating expenses per Boe increased 9% to $6.96.

Depreciation, depletion and amortization (DD&A) increased $14.9 million or 59% primarily due to a 37% increase in our DD&A rate and a 16% increase in equivalent production. The increase in our DD&A rate in the first quarter of 2011 compared to the first quarter of 2010 resulted primarily from increases throughout 2010 and the first quarter of 2011 from increased net book value on new reserves added. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Mid-Stream

Our mid-stream revenues were $1.4 million or 3% lower for the first quarter of 2011 as compared to the first quarter of 2010 primarily due to lower NGL and natural gas prices. The average price for natural gas sold decreased 24% and the average price for NGLs sold decreased 1%. Gas processing volumes per day increased 13% between the comparative quarters and NGLs sold per day increased 29% 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 2010 and increased capacity of processing facilities. NGLs sold volumes per day increased due to both an increase in volumes processed, upgrades to several of our processing facilities and the doubling in size of our Hemphill facility in the Texas Panhandle. Gas gathering volumes per day increased 3% primarily from well connections throughout 2010.

Operating costs decreased $3.7 million or 11% in the first quarter of 2011 compared to the first quarter of 2010 primarily due to a 13% decrease in prices paid for natural gas purchased. Depreciation and amortization decreased $0.2 million, or 4%, primarily due to decreased amortization on our intangible asset. For 2011, we anticipate an increase in well connections over 2010 due to anticipated drilling activity by operators in the areas of our existing gathering systems as along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

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.

General and administrative expenses increased $0.6 million or 10% in the first quarter of 2011 compared to the first quarter of 2010 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $0.1 million between the comparative first quarters of 2011 and 2010. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate decreased by 54% and our average debt outstanding was $144.2 million higher in the first quarter of 2011 as compared to the first quarter of 2010 due to the acquisition in 2010 and construction of new rigs in 2011. Total interest incurred increased $0.3 million for the first quarter of 2011 and $0.3 million for the first quarter of 2010 due to interest rate swap settlements.

Income tax expense increased $3.0 million or 13% in the first quarter of 2011 compared to the first quarter of 2010 primarily due to increased income. Our effective tax rate was 38.3% for both the first quarters of 2011 and 2010. There was no current income tax expense for the first quarter of 2011 as compared with $2.2 million or 10% of total income tax expense in the first quarter of 2010 due to expected bonus depreciation for 2011. We did not pay any income taxes in the first quarter of 2011.

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 expre 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 and drilling prospects;
- estimates of our proved oil, NGLs and natural gas reserves;
- oil, NGLs and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil, NGLs and natural gas reserves;
- 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;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results; and
- our ability to timely secure third party services used in completing our wells.

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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 availability of and nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases 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, NGLs 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, NGLs 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 2011 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 $326,000 per month ($3.9 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 $177,000 per month ($2.1 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 $152,000 per month ($1.8 million annualized) change in our pre-tax operating cash flow.

We use hedging transactions to manage the risk associated with price volatility. 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. Currently, we also have three basis swaps that do not qualify as cash flow hedges. 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.

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Oil and Natural Gas Segment:

At March 31, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr 11 Dec 11	Crude oil swap	4,000 Bbl/day	$84.28	WTI NYMEX
Jan 12 Dec 12	Crude oil swap	3,000 Bbl/day	$90.92	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	1,000 Bbl/day	$101.08	WTI NYMEX
Apr 11 Dec 11	Natural gas swap	10,000 MMBtu/day	$4.43	CEGT
Apr 11 Dec 11	Natural gas swap	70,000 MMBtu/day	$4.87	IF NYMEX (HH)
Apr 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	$5.06	IF NYMEX (HH)
Jan 12 Dec 12	Natural gas swap	15,000 MMBtu/day	$5.62	IF PEPL
Apr 11 Dec 11	Liquids swap (1)	644,406 Gal/mo	$0.96	OPIS Conway

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

At March 31, 2011, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Apr 11 Dec 11	Natural gas basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0 NYMEX
Apr 11 Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.21)	CEGT NYMEX
Apr 11 Dec 11	Natural gas basis differential swap	10,000 MMBtu/day	($0.23)	PEPL NYMEX

After March 31, 2011, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
Jan 12 Dec 12	Crude oil swap	1,000 Bbl/day	$107.31	WTI NYMEX
Jan 13 Dec 13	Crude oil swap	500 Bbl/day	$104.40	WTI NYMEX

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit facility. That debt, at our election bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our 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. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate. Based on our average outstanding long-term debt subject to a variable rate in the first three months of 2011, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $1.5 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, 2011 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, 2011 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.

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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, 2010. 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, if any, and in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010, 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, 2010.

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, 2011:

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, 2011 to January 31, 2011	6,147	$ 47.06	6,147	0
February 1, 2011 to February 28, 2011	1,351	52.36	1,351	0
March 1, 2011 to March 31, 2011	26,819	58.48	26,819	0
Total	34,317	$ 56.19	34,317	0

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the first quarter 2011 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

Item 5. Other Information

Not applicable.

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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.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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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 3, 2011	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: May 3, 2011	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer