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 September 30, 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 October 24, 2011, 48,150,732 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 within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document which address activities, events or developments which we expect or anticipate will or may occur in the future, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts” and similar expressions are used to identify forward-looking statements.

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the number of wells we plan to drill or rework;
- prices for oil, NGLs and natural gas;
- demand for oil, NGLs and natural gas;
- our exploration and drilling prospects;
- the 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;
- the number of 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;
- our ability to timely secure third party services used in completing our wells; and
- our ability to transport or convey our oil or natural gas production to established pipeline systems.

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 our actual results to differ materially from our expectations, including:

- the risk factors discussed in this document 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 document to reflect the occurrence of unanticipated events.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2011	December 31, 2010
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,160	$ 1,359
Accounts receivable, net of allowance for doubtful accounts of $5,083 at both September 30, 2011 and at December 31, 2010	153,827	130,142
Materials and supplies	8,096	6,316
Current derivative assets (Note 10)	41,257	5,568
Current income tax receivable	11,868	25,211
Current deferred tax asset	10,013	13,537
Prepaid expenses and other	9,749	6,047
Total current assets	235,970	188,180
Property and equipment:		
Drilling equipment	1,386,388	1,273,861
Oil and natural gas properties on the full cost method:		
Proved properties	3,166,022	2,738,093
Undeveloped leasehold not being amortized	184,540	175,065
Gas gathering and processing equipment	258,854	199,564
Transportation equipment	33,749	31,688
Other	35,607	28,511
	5,065,160	4,446,782
Less accumulated depreciation, depletion, amortization and impairment	2,242,812	2,047,031
Net property and equipment	2,822,348	2,399,751
Deferred financing costs, net	5,815	0
Goodwill	62,808	62,808
Other intangible assets, net	2,168	3,022
Non-current derivative assets (Note 10)	23,989	2,537
Other assets	12,153	12,942
Total assets	$ 3,165,251	$ 2,669,240

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

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

	September 30, 2011	December 31, 2010
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 105,493	$ 89,885
Accrued liabilities (Note 5)	60,588	30,093
Contract advances	1,392	2,582
Current derivative liabilities (Note 10)	552	14,446
Current portion of other long-term liabilities (Note 6)	10,031	10,122
Total current liabilities	178,056	147,128
Long-term debt (Note 6)	305,400	163,000
Non-current derivative liabilities (Note 10)	0	4,359
Other long-term liabilities (Note 6)	112,701	88,030
Deferred income taxes	658,659	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, 48,150,732 and 47,910,431 shares issued, respectively	9,540	9,493
Capital in excess of par value	404,892	393,501
Accumulated other comprehensive gain (loss)	37,323	(6,851)
Retained earnings	1,458,680	1,314,474
Total shareholders' equity	1,910,435	1,710,617
Total liabilities and shareholders' equity	$ 3,165,251	$ 2,669,240

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 128,927	$ 85,004	$ 342,098	$ 217,919
Oil and natural gas	134,897	96,562	376,393	286,751
Gas gathering and processing	60,688	37,429	144,820	114,908
Other income (loss), net	(667)	(879)	(566)	9,691
Total revenues	323,845	218,116	862,745	629,269
Expenses:				
Contract drilling:				
Operating costs	73,004	45,406	190,086	132,847
Depreciation	20,818	18,469	57,333	48,700
Oil and natural gas:				
Operating costs	29,598	27,092	93,796	75,943
Depreciation, depletion and amortization	47,195	30,091	132,013	81,746
Gas gathering and processing:				
Operating costs	53,299	30,743	119,143	92,407
Depreciation and amortization	4,017	3,823	11,627	11,746
General and administrative	7,800	6,637	22,188	19,372
Interest, net	1,351	0	2,078	0
Total operating expenses	237,082	162,261	628,264	462,761
Income before income taxes	86,763	55,855	234,481	166,508
Income tax expense (benefit):				
Current	(3,949)	(8,553)	(3,949)	(2,488)
Deferred	37,352	29,917	94,224	66,177
Total income taxes	33,403	21,364	90,275	63,689
Net income	$ 53,360	$ 34,491	$ 144,206	$ 102,819
Net income per common share:				
Basic	$ 1.12	$ 0.73	$ 3.03	$ 2.18
Diluted	$ 1.11	$ 0.73	$ 3.01	$ 2.17

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

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

	Nine Months Ended September 30, 2011	2010
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 144,206	$ 102,819
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	201,924	142,930
Unrealized gain on derivatives	(3,611)	(1,202)
Deferred tax expense	94,224	66,177
(Gain) loss on disposition of assets	462	(9,579)
Stock compensation plans	10,780	6,603
Other	2,740	2,113
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(26,118)	(35,863)
Accounts payable	(30,439)	(7,924)
Material and supplies inventory	(1,780)	346
Accrued liabilities	13,487	5,121
Contract advances	(1,190)	720
Other – net	13,166	11,635
Net cash provided by operating activities	417,851	283,896
INVESTING ACTIVITIES:		
Capital expenditures	(541,044)	(335,821)
Producing property and other acquisitions	(50,525)	(92,642)
Proceeds from disposition of assets	7,779	34,335
Other - net	0	324
Net cash used in investing activities	(583,790)	(393,804)
FINANCING ACTIVITIES:		
Borrowings under line of credit	334,100	205,000
Payments under line of credit	(441,700)	(100,000)
Proceeds from issuance of senior subordinated notes, net of offering costs	243,950	0
Proceeds from exercise of stock options	644	122
Book overdrafts	28,746	4,779
Net cash provided by financing activities	165,740	109,901
Net decrease in cash and cash equivalents	(199)	(7)
Cash and cash equivalents, beginning of period	1,359	1,140
Cash and cash equivalents, end of period	$ 1,160	$ 1,133

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
	(In thousands)			
Net income	$ 53,360	$ 34,491	$ 144,206	$ 102,819
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $27,015, $2,753, $28,201 and $18,780	43,154	4,148	45,123	30,014
Reclassification - derivative settlements, net of tax of ($771), ($5,646), $1,008 and ($13,708)	(1,232)	(8,816)	1,608	(21,832)
Ineffective portion of derivatives, net of tax of ($899), ($67), ($1,601) and ($231)	(1,437)	(109)	(2,557)	(374)
Comprehensive income	$ 93,845	$ 29,714	$ 188,380	$ 110,627

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO THE UNAUDITED 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 along 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 our management's opinion, the accompanying condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state our:

- Balance Sheets at September 30, 2011 and December 31, 2010;
- Statements of Income for the three and nine months ended September 30, 2011 and 2010;
- Cash Flows for the nine months ended September 30, 2011 and 2010; and
- Statements of Comprehensive Income for the three and nine months ended September 30, 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 unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three and nine months ended September 30, 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 and nine month periods ended September 30, 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 November 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.

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. Once incurred, a write-down of oil and natural gas properties is not reversible.

At September 30, 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 at September 30, 2011, consisted of swaps covering 1.8 MMBoe in 2011, 4.7 MMBoe in 2012 and 0.7 MMBoe in 2013. The effect of those hedges on the September 30, 2011 ceiling test was a $13.7 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 Unaudited 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 closing 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. This acquisition targeted 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 consisting of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper and Ellis Counties in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. The acquisition also included in excess of 12,000 net held by production acres in the area for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash, subject to closing adjustments, from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

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 September 30, 2011:			
Basic earnings per common share	$ 53,360	47,687	$ 1.12
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	0	281	(0.01)
Diluted earnings per common share	$ 53,360	47,968	$ 1.11
For the three months ended September 30, 2010:			
Basic earnings per common share	$ 34,491	47,358	$ 0.73
Effect of dilutive stock options, restricted stock and SARs	0	137	0.00
Diluted earnings per common share	$ 34,491	47,495	$ 0.73

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 September 30,	
	2011	2010
Stock options and SARs	149,665	361,421
Average Exercise Price	$ 58.41	$ 48.05

	Income (Numerator)		Weighted Shares (Denominator)		Per-Share Amount
	(In thousands except per share amounts)				
For the nine months ended September 30, 2011:					
Basic earnings per common share	$	144,206	47,642	$	3.03
Effect of dilutive stock options, restricted stock and SARs		0	290		(0.02)
Diluted earnings per common share	$	144,206	47,932	$	3.01
For the nine months ended September 30, 2010:					
Basic earnings per common share	$	102,819	47,217	$	2.18
Effect of dilutive stock options, restricted stock and SARs		0	167		(0.01)
Diluted earnings per common share	$	102,819	47,384	$	2.17

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:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Stock options and SARs	73,500	233,401
Average Exercise Price	$ 64.43	$ 53.12

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	September 30, 2011	December 31, 2010
	(In thousands)	
Employee costs	$ 16,487	$ 16,499
Lease operating expense	6,875	6,214
Taxes	24,804	1,310
Interest payable	7,010	667
Hedge settlements	524	1,634
Other	4,888	3,769
Total accrued liabilities	$ 60,588	$ 30,093

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:

	September 30, 2011	December 31, 2010
	(In thousands)	
Credit agreement with average interest rates, of 2.2% and 3.5% at September 30, 2011 and December 31, 2010, respectively	$ 55,400	$ 163,000
6.625% senior subordinated notes due 2021	250,000	0
Total long-term debt	$ 305,400	$ 163,000

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) that replaces our previous credit agreement which was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect as the commitment amount (currently $250.0 million) or the value of the borrowing base as determined by the lenders (currently $600.0 million), but in either event, not to exceed the maximum credit agreement amount of $750.0 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, in connection with this new credit agreement, we paid $1.6 million in origination, agency, syndication and other related fees. We are amortizing these fees over the life of the credit agreement.

The amount of the borrowing base, which is subject to redetermination on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. 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 agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term 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 term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the 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 September 30, 2011, $50.0 million of our $55.4 million in outstanding borrowings were subject to LIBOR.

We used borrowings under the credit agreement to pay off the commitments issued under our previous credit agreement. In addition, we can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of midstream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes of the Borrowers.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of September 30, 2011, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of our 6.625% Senior Subordinated Notes due 2021 (the Notes). The Notes were issued at par and mature on May 15, 2021. We received net proceeds of approximately $244.0 million after deducting fees of approximately $6.0 million. Those fees are being amortized as deferred financing costs over the life of the Notes. We used the net proceeds to repay outstanding borrowings under our credit agreement, which was $220.3 million on May 18, 2011. The remaining proceeds were used for general working capital purposes.

The Notes are guaranteed by our wholly-owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several. Any subsidiaries of Unit other than the Guarantors are minor. There are no significant restrictions on the ability of Unit to receive funds from its subsidiaries through dividends, loans, advances or otherwise.

The Notes were issued under an Indenture dated as of May 18, 2011, between us and Wilmington Trust FSB, as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors and the Trustee, establishing the terms and providing for the issuance of the Notes (the Supplemental Indenture). The discussion of the Notes in this quarterly report is qualified by and subject to the actual terms of the Indenture and the First Supplemental Indenture.

The Notes bear interest at a rate of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year, beginning on November 15, 2011), and will mature on May 15, 2021.

On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. Before May 15, 2014, we may on any one or more occasions redeem up to 35% of the original principal amount of the Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, provided that at least 65% of the original principal amount of the Notes remains outstanding after each redemption. In addition, at any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The Indenture and the Supplemental Indenture contain customary events of default. The Indenture governing the Notes contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2011.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligations	$ 92,802	$ 69,265
Workers' compensation	17,921	17,566
Separation benefit plans	6,480	5,690
Gas balancing	3,263	3,263
Deferred compensation plan	2,266	2,368
	122,732	98,152
Less current portion	10,031	10,122
Total other long-term liabilities	$ 112,701	$ 88,030

The estimated annual payments due under the terms of our other long-term liabilities during each of the five successive twelve month periods beginning October 1, 2011 (and through 2016) are $10.0 million, $16.9 million, $3.7 million, $3.0 million and $57.8 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 (AROs). 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 plugging costs associated with our oil and gas wells.

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In thousands)	
ARO liability, January 1:	$ 69,265	$ 56,404
Accretion of discount	2,598	2,138
Liability incurred (1)	12,674	2,901
Liability settled	(831)	(622)
Revision of estimates (2)	9,096	3,822
ARO liability, September 30:	92,802	64,643
Less current portion	2,074	1,617
Total long-term ARO liability	$ 90,728	$ 63,026

(1) Liability incurred in 2011 includes estimates for new wells acquired.

(2) Plugging liability estimates were revised upward in both 2011 and 2010 due to increases in the cost of services used to plug wells over the preceding years.

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.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). In May 2011, the FASB issued ASU 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS.* ASU 2011-4 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the Board’s intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The update is effective for annual periods beginning after December 15, 2011. We are in the process of evaluating the impact, if any, the adoption of this update will have on our financial statements.

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05 – *Presentation of Comprehensive Income.* This ASU amends the Codification to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. The amendments to the Codification in the ASU do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income.

ASU 2011-05 should be applied retrospectively. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We are in the process of evaluating the option we will choose to present comprehensive income and the impact it will have on our financial statements.

Testing Goodwill for Impairment. In August 2011, the FASB issued ASU 2011-08 – *Intangibles-Goodwill and Other (ASC 350): Testing Goodwill for Impairment.* This ASU is intended to simplify how entities, both public and nonpublic, test goodwill for impairment. ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is "more likely than not" that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in ASC 350, *Intangibles-Goodwill and Other.* The more-likely-than-not threshold is defined as having a likelihood of more than 50%.

ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

NOTE 9 – STOCK-BASED COMPENSATION

For the three and nine months ended September 30, 2011, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.7 million and $7.7 million, respectively. We also capitalized for the same periods stock compensation cost for oil and natural gas properties of $0.6 million and $1.9 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.1 million and $3.0 million, respectively. For the three and nine months ended September 30, 2010, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.8 million and $8.3 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.7 million and $2.0 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.1 million and $3.2 million, respectively. The remaining unrecognized compensation cost related to unvested awards at September 30, 2011 is approximately $11.2 million of which $2.2 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 years.

We did not grant any SARs or stock options (other than the non-employee director options discussed below) during either of the three or nine month periods ending September 30, 2011 and 2010.

The table below shows the estimates of the fair value of the stock options granted to our non-employee directors under the Unit Corporation 2000 Non-employee Directors Stock Option Plan during the periods using the Black-Scholes model and applying the estimated values also presented in the table:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Options granted [1]	31,500	52,504
Estimated fair value (in millions)	$ 0.7	$ 0.8
Estimate of stock volatility	0.48	0.45
Estimated dividend yield	0%	0%
Risk free interest rate	2%	2%
Expected annual life based on prior experience	5	5
Forfeiture rate	0 %	0%

(1) On May 29, 2009, eight of our directors were each issued 3,063 options contingent on shareholder approval, which was received at the May 5, 2010 annual shareholders' meeting. These 24,504 options granted and vested simultaneously with that approval.

Expected volatilities are based on the historical volatility of our stock. Within the model, we use historical data to estimate stock option exercise and termination rates and aggregate groups that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the LIBOR rate using the term over which it is anticipated the grant will be exercised. The stock options granted in the second quarter of 2011 increased stock compensation expense for the third quarter and first nine months of 2011 by $0.4 million and $0.6 million, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Shares granted	12,402	192,272	209,150	440,655
Estimated fair value (in millions)	$ 0.6	$ 6.0	$ 10.9	$ 16.6
Percentage of shares granted expected to be distributed	95%	89%	93%	91%

The restricted stock awards granted during the first three and nine months of 2011 will be recognized over a two- and three-year vesting period, except for a portion of those granted to certain executive officers in the first quarter of 2011. Thirty percent of the shares granted to the designated executive officers, or 20,062 shares (the performance shares), will cliff vest in the first half of 2014. The actual number of performance shares that vest in 2014 will be based on the company's achievement of certain performance criteria over a three-year period, and will range from 50% to 150% of the 20,062 restricted shares granted as performance shares. Total 2011 awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first nine months of 2011 by an aggregate of $3.5 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 agreement. 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. In May 2011, in association with the repayment of outstanding borrowings under our credit agreement, we terminated our two outstanding interest rate swaps that were previously accounted for as cash flow hedges, resulting in an increase of approximately $1.5 million in interest expense. Approximately $1.1 million of that expense was capitalized and will be amortized over the life of the assets.

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 September 30, 2011, our derivative transactions consisted of the following types of hedges:

- *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.

Oil and Natural Gas Segment:

At September 30, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct'11 – Dec'11	Crude oil – swap	4,000 Bbl/day	$84.28	WTI – NYMEX
Jan'12 – Dec'12	Crude oil – swap	4,500 Bbl/day	$95.91	WTI – NYMEX
Jan'13 – Dec'13	Crude oil – swap	2,000 Bbl/day	$102.05	WTI – NYMEX
Oct'11 – Dec'11	Natural gas – swap	10,000 MMBtu/day	$ 4.43	CEGT
Oct'11 – Dec'11	Natural gas – swap	70,000 MMBtu/day	$ 4.87	IF – NYMEX (HH)
Oct'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	30,000 MMBtu/day	$ 5.05	IF – NYMEX (HH)
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$ 5.62	IF – PEPL
Oct'11 – Dec'11	Liquids – swap (1)	2,024,418 Gal/mo	$1.07	OPIS – Conway
Oct'11 – Dec'11	Liquids – swap (1)	1,240,068 Gal/mo	$1.00	OPIS – Mont Belvieu
Jan'12 – Mar'12	Liquids – swap (1)	1,350,014 Gal/mo	$1.10	OPIS – Conway
Jan'12 – Mar'12	Liquids – swap (1)	1,155,018 Gal/mo	$0.91	OPIS – Mont Belvieu
Apr'12 – Dec'12	Liquids – swap (2)	180,006 Gal/mo	$2.11	OPIS – Conway
Apr'12 – Jun'12	Liquids – swap (3)	690,028 Gal/mo	$0.79	OPIS – Mont Belvieu

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

At September 30, 2011, the following non-qualifying cash flow derivatives were outstanding:

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

The following tables present the fair values of our derivative transactions and the location within our balance sheets where those values are recorded:

	Balance Sheet Location	Derivative Assets Fair Value September 30, 2011	December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 41,257	$ 5,091
Long-term	Non-current derivative assets	23,989	2,537
Total derivatives designated as hedging instruments		65,246	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		$ 65,246	$ 8,105

	Balance Sheet Location	Derivative Liabilities Fair Value September 30, 2011	Derivative Liabilities Fair Value December 31, 2010
Derivatives designated as hedging instruments		(In thousands)	
Interest rate swaps:			
Current	Current derivative liabilities	$ 0	$ 1,139
Long-term	Non-current derivative liabilities	0	475
Commodity derivatives:			
Current	Current derivative liabilities	342	13,166
Long-term	Non-current derivative liabilities	0	3,884
Total derivatives designated as hedging instruments		342	18,664
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current derivative liabilities	210	141
Total derivatives not designated as hedging instruments		210	141
Total derivative liabilities		$ 552	$ 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 September 30, 2011 and 2010, we had a gain of $37.3 million and $12.3 million, net of tax, respectively, in accumulated OCI.

Based on market prices at September 30, 2011, we expect to transfer a gain of approximately $25.0 million, net of tax, included in accumulated OCI during the next 12 months in the related month of settlement. The commodity derivative instruments existing as of September 30, 2011 are expected to mature by December 2013.

Certain derivatives do not qualify as cash flow hedges. Currently, three of our basis swaps do not qualify as cash flow hedges. For these derivatives, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in oil and natural gas revenues in our unaudited condensed consolidated statements of income. Changes in the fair value of derivatives 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 Unaudited Condensed Consolidated Statement of Income (cash flow hedges) for the nine months ended September 30:

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	$ 0	$ (1,193)
Commodity derivatives	37,323	13,459
Total	$ 37,323	$ 12,266

(1) Net of taxes.

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended September 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 2,003	$ 14,760	$ 2,336	$ 176
Interest rate swaps	Interest, net	0	(298)	0	0
	Total	$ 2,003	$ 14,462	$ 2,336	$ 176

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

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (derivatives not designated as hedging instruments) for the three months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (61)	$ (427)
Total		$ (61)	$ (427)

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (cash flow hedges) for the nine months ended September 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ (882)	$ 36,447	$ 4,158	$ 605
Interest rate swaps	Interest, net	(1,734)	(907)	0	0
	Total	$ (2,616)	$ 35,540	$ 4,158	$ 605

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

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statement of Income (derivatives not designated as hedging instruments) for the nine months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (1,008)	$ 597
Total		$ (1,008)	$ 597

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.

The following tables set forth our recurring fair value measurements:

	September 30, 2011		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets:			
Commodity derivatives	$ 39,565	$ 25,129	$ 64,694

	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, NGLs 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.

The following tables reconcile our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended September 30, 2011		For the Nine Months Ended September 30, 2011	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$ 0	$ 11,749	$ (1,614)	$ 10,868
Total gains or (losses) (realized and unrealized):				
Included in earnings [(1)]	0	4,046	(1,734)	11,923
Included in other comprehensive income	0	13,182	1,614	13,264
Settlements	0	(3,848)	1,734	(10,926)
End of period	$ 0	$ 25,129	$ 0	$ 25,129
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at end of period	$ 0	$ 198	$ 0	$ 997

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

	Net Derivatives			
	For the Three Months Ended September 30, 2010		For the Nine Months Ended September 30, 2010	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,971)	$ 33,313	$ (1,948)	$ 19,948
Total gains or (losses) (realized and unrealized):				
Included in earnings [(2)]	(298)	16,558	(907)	44,322
Included in other comprehensive income (loss)	39	(1,266)	16	10,646
Purchases, issuance and settlements	298	(16,809)	907	(43,120)
End of period	$ (1,932)	$ 31,796	$ (1,932)	$ 31,796
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains relating to assets still held at end of period	$ 0	$ (251)	$ 0	$ 1,202

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

Based on our valuation at September 30, 2011, we determined that the non-performance risk with regard to our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At September 30, 2011, the carrying values on the unaudited condensed 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.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and consideration of our non-performance risk, long-term debt associated with our credit agreement at September 30, 2011 approximates its fair value.

The carrying amount of long-term debt associated with the Notes reported in the consolidated balance sheet as of September 30, 2011 was $250.0 million. We estimate the fair value of these Notes using quoted marked prices at September 30, 2011 was $249.4 million.

NOTE 12 - INDUSTRY SEGMENT INFORMATION

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

- Contract drilling,
- Oil and natural gas and
- Midstream

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 midstream segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization and impairment. Our oil and natural gas production outside the United States is not significant.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In thousands)			
Revenues:				
Contract drilling	$ 140,193	$ 96,705	$ 381,982	$ 246,252
Elimination of inter-segment revenue	(11,266)	(11,701)	(39,884)	(28,333)
Contract drilling net of inter-segment revenue	128,927	85,004	342,098	217,919
Oil and natural gas	134,897	96,562	376,393	286,751
Gas gathering and processing	79,919	47,864	200,821	148,606
Elimination of inter-segment revenue	(19,231)	(10,435)	(56,001)	(33,698)
Gas gathering and processing net of inter-segment revenue	60,688	37,429	144,820	114,908
Other, net	(667)	(879)	(566)	9,691
Total revenues	$ 323,845	$ 218,116	$ 862,745	$ 629,269
Operating income:				
Contract drilling	$ 35,105	$ 21,129	$ 94,679	$ 36,372
Oil and natural gas	58,104	39,379	150,584	129,062
Gas gathering and processing	3,372	2,863	14,050	10,755
Total operating income (1)	96,581	63,371	259,313	176,189
General and administrative expense	(7,800)	(6,637)	(22,188)	(19,372)
Interest expense, net	(1,351)	0	(2,078)	0
Other income (loss), net	(667)	(879)	(566)	9,691
Income before income taxes	$ 86,763	$ 55,855	$ 234,481	$ 166,508

(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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying unaudited condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of September 30, 2011, and the related unaudited condensed consolidated statements of income and comprehensive income for the three and nine-month periods ended September 30, 2011 and 2010 and the unaudited condensed consolidated statements of cash flows for the nine-month periods ended September 30, 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 unaudited 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 income, 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
November 3, 2011

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

Please read the following discussion and our unaudited condensed consolidated financial statements and related notes with 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.

- *Midstream* – 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, NGLs 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.

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, borrowings under our credit agreement and the remaining proceeds from the Notes.

Executive Summary

Contract Drilling

The rate at which our drilling rigs were used ("our utilization rate") for the third quarter 2011 was 63%, compared to 60% and 54% for the second quarter of 2011 and the third quarter of 2010, respectively.

Dayrates for the third quarter of 2011 averaged $19,309, an increase of 2% from the second quarter of 2011 and an increase of 22% from the third quarter of 2010. These increases were primarily the result of increased use of drilling rigs in the 1,000 to 1,500 horsepower range that are used for horizontal drilling and also provide for higher rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the third quarter of 2011 increased 10% over the second quarter of 2011 and 41% over the third quarter of 2010. The increases were primarily due to increases in dayrates and utilization over the comparative periods as discussed above.

Operating cost per day for the third quarter of 2011 increased 5% over the second quarter of 2011 and increased 34% over the third quarter of 2010. The increase over the second quarter 2011 and the third quarter of 2010 is primarily due to increases in direct expenses due to pay increases for rig personnel and to a lesser extent from increases in rig servicing costs.

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 natural gas market, operators are focusing on drilling for oil and NGLs. Approximately 79% of our drilling rigs working today are drilling for oil or NGLs. Of those, approximately 95% are drilling horizontal or directional wells.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now completed and are working in the Bakken shale. Each of these five new drilling rigs is initially working under a two-year drilling contract. During the third quarter of 2011,we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. Delivery of the two rigs is scheduled for the fourth quarter of 2011. Both drilling rigs will be for our Rocky Mountain division operations. On completion of the additional drilling rigs, we will have 128 drilling rigs in our fleet.

Our anticipated 2011 capital expenditures for this segment are $174.0 million.

As of October 19, 2011, we had 61 term drilling contracts with original terms ranging from six months to three years. Nine of these contracts are up for renewal in 2011 and 52 are up for renewal in 2012 and later. These contracts include all seven term contracts for the new drilling rigs discussed above. Term contracts may contain a fixed rate for the duration of the contract or provide for 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. This acquisition targeted 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.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper and Ellis Counties in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. The acquisition also included in excess of 12,000 net held by production acres in the area for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash, subject to closing adjustments, from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The proved reserves associated with the acquisition are approximately 31.2 Bcfe

(99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

Third quarter 2011 production was 3,123,000 barrels of oil equivalent (Boe) per day, a 5% increase over the second quarter of 2011 and a 26% increase over the third quarter of 2010. The increase in production came primarily from oil and NGL rich prospects where we completed and brought new wells online and, to a lesser extent, from production associated with the acquisitions discussed above. Third quarter 2011 oil and NGL production was 38% of our total production compared to 30% of our total production over the third quarter of 2010. 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 2010 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.

Third quarter 2011 oil and natural gas revenues increased 2% over the second quarter of 2011 and increased 40% over the third quarter of 2010. These increases were primarily due to increased production and for the increase over the third quarter of 2010, also increased oil and liquid prices.

Our oil and NGL prices for the third quarter of 2011 decreased 4% and remained unchanged, respectively, over the second quarter of 2011 and increased 29% and 43%, respectively, over the third quarter of 2010. Natural gas prices for the third quarter of 2011 increased 2% compared to second quarter 2011 and decreased 21% compared to the third quarter of 2010.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 7% over the second quarter of 2011 and increased 52% over the third quarter of 2010. The increases were primarily attributable to increased production and a $4.5 million decrease in gross production taxes in the third quarter of 2011, due to refunds of production taxes attributable to high-cost gas wells, partially offset by increases in lease operating expenses.

Operating cost per Boe produced for the third quarter of 2011 decreased 15% over the second quarter of 2011 and decreased 13% over the third quarter of 2010. The decreases were primarily due to the gross production tax refund received in the third quarter of 2011 for high cost gas tax credits, partially offset by increases in lease operating expenses (LOE) due to increased workover expense and higher saltwater disposal fees.

For 2011, we currently have hedged approximately 59% of our anticipated daily oil production, approximately 58% of our anticipated natural gas production and approximately 40% of our anticipated NGLs production (percentages based on our third quarter 2011 production).

Currently for 2012 we have hedged 4,500 Bbls per day of oil production and 45,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $95.91 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.33. The average basis differential for the applicable swaps is ($0.28). We have NGL hedges of 1,988 Bbls per day in the first quarter, 683 Bbls per day in the second quarter, 140 Bbls per day in the third quarter, and 140 Bbls per day in the fourth quarter. The NGLs are hedged under swap contracts at an average price of $42.53 per barrel in the first quarter, $44.47 per barrel in the second quarter, $88.41 per barrel in the third quarter, and $88.41 per barrel in the fourth quarter.

Currently for 2013 we have hedged 2,000 Bbls per day of oil production. The oil production is hedged under swap contracts at an average price of $102.05 per barrel.

During the first nine months of 2011, we drilled 119 gross wells (62.20 net wells). During the second quarter, we increased our estimated capital expenditures for 2011 from $415.0 million to $435.0 million with the increase primarily being associated with the purchase of acreage both within our existing core plays and in areas outside of our core plays. For the year, we plan to drill 160 gross wells and we are also increasing our anticipated annual production guidance to a range between 11.8 to 12.1 MMBoe from our previous guidance of 11.3 to 11.6 MMBoe.

Midstream

Third quarter 2011 liquids sold per day increased 26% over the second quarter of 2011 and increased 73% over the third quarter of 2010. The increases resulted from upgrades and expansions to existing plants and the connection of new wells. For the third quarter of 2011, gas processed per day increased 43% over the second quarter of 2011 and 54% over the third 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 third quarter of 2011, gas gathered per day increased 20% over the second quarter of 2011 and increased 25% over the third quarter of 2010 primarily from well connects throughout 2011.

NGL prices in the third quarter of 2011 decreased 1% over the price received in the second quarter of 2011 and increased 29% over the price received in the third quarter of 2010. The price of NGLs as compared to natural gas affects the revenue in our midstream 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.

Direct profit (midstream revenues less midstream operating expense) for the third quarter of 2011 decreased 3% from the second quarter of 2011 and increased 11% over the third quarter of 2010. The decrease from second quarter of 2011 resulted primarily from the increased cost of gas purchased. The increase over the third quarter of 2010 was due to increased production as limited by the increased cost of gas purchased.

Total operating cost for our midstream segment for the third quarter of 2011 increased 45% over the second quarter of 2011 and 73% over the third quarter of 2010 due primarily to the increase in gas purchased due to increased volumes.

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 expansion of this plant, the total processing capacity at our Hemphill facility has increased to approximately 100.0 MMcf per day. During the third quarter of 2011, we increased the capacity of this plant by 20 MMcf per day by replacing the turbo expander center section.

In our Mid-continent operations, we are in the process of replacing the existing plant on our Cashion system with a high-efficiency gas processing plant. The new plant is expected to be operational during the first quarter of 2012. It will increase our processing capacity and will improve our liquids recovery capability by 12 to 15%. The Cashion plant gathers gas across Logan, Canadian, Oklahoma and Kingfisher Counties in Oklahoma. In the Mississippi Lime play in Grant County, Oklahoma, our new gathering system and processing plant became operational in October. One well is online and three more wells are in the process of being connected. We anticipate an additional 25 to 30 wells to be connected during 2012 due to active drilling by multiple producers in the area around the plant. This is our entrance into the Mississippi Lime play.

In our Appalachian operations, we are in the final stages of completing 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. Currently, we have four wells connected with an expected total initial flow volume in the 8 to 10 MMcf per day range. Three additional wells have been drilled and are waiting on completion prior to being connected. We anticipate this pipeline will be operational during the fourth quarter of 2011. In addition to the Preston County pipeline, we recently signed a letter of intent with a third party to construct a pipeline in Allegheny and Butler Counties of Pennsylvania. First flow of gas from this new system is expected to occur in the fourth quarter of 2011. Expectations are that the first well will flow up to 10 MMcf per day, and we anticipate four more wells to be drilled and connected during the first half of 2012.

Our anticipated capital expenditures for 2011 are $86.0 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 agreement. 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.

The following is a summary of certain financial information as of September 30, 2011 and 2010 and for the nine months ended September 30, 2011 and 2010:

	September 30, 2011	September 30, 2010	% Change
	(In thousands except percentages)		
Working capital	$ 57,914	$ 35,480	63 %
Long-term debt	$ 305,400	$ 135,000	126 %
Shareholders' equity	$ 1,910,435	$ 1,682,868	14 %
Ratio of long-term debt to total capitalization	14 %	7 %	100 %
Net income	$ 144,206	$ 102,819	40 %
Net cash provided by operating activities	$ 417,851	$ 283,896	47 %
Net cash used in investing activities	$ (583,790)	$ (393,804)	48 %
Net cash provided by financing activities	$ 165,740	$ 109,901	51 %

The following table summarizes certain operating information:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	74	58.2	27%
Total number of drilling rigs owned at the end of the period	126	123	2%
Average dayrate	$ 18,663	$ 15,037	24%
Oil and Natural Gas:			
Oil production (MBbls)	1,767	1,002	76%
Natural gas liquids production (MBbls)	1,623	1,143	42%
Natural gas production (MMcf)	32,730	30,121	9%
Average oil price per barrel received	$ 86.80	$ 67.05	29%
Average oil price per barrel received excluding hedges	$ 93.75	$ 74.11	27%
Average NGL price per barrel received	$ 43.72	$ 35.91	22%
Average NGL price per barrel received excluding hedges	$ 44.65	$ 35.70	25%
Average natural gas price per mcf received	$ 4.33	$ 5.71	(24)%
Average natural gas price per mcf received excluding hedges	$ 3.94	$ 4.27	(8)%
Midstream:			
Gas gathered—MMBtu/day	201,788	182,390	11%
Gas processed—MMBtu/day	102,493	81,157	26%
Gas liquids sold — gallons/day	378,585	264,679	43%
Number of natural gas gathering systems	34	34	0%
Number of processing plants	10	8	25%

At September 30, 2011, we had unrestricted cash totaling $1.2 million and had borrowed $55.4million of the $250.0 million we had elected to have currently available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

On May 18, 2011, we completed the sale of $250.0 million aggregate principal amount of 6.625% Senior Subordinated Notes due 2021. The Notes were issued at par and mature on May 15, 2021. The net proceeds were used to repay outstanding borrowings under our credit agreement, which had approximately $220.3 million outstanding as of May 18, 2011. The remaining proceeds were used for general working capital purposes.

Working Capital

Typically, our working capital balance fluctuates. This is 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 $57.9 million and $35.5 million as of September 30, 2011 and 2010, respectively. The effect of our hedging activity increased working capital by $25.0 million as of September 30, 2011 and increased working capital by $11.4 million as of September 30, 2010.

Contract Drilling

Many factors influence the number of drilling rigs we are working at any one time 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 and 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 also increased. 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 of 2011 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 those drilling rigs have the horsepower ideally suited for horizontal drilling. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For the first nine months of 2011, our average dayrate was $18,663 per day compared to $15,037 per day for the first nine months of 2010. The average number of our drilling rigs used in the first nine months of 2011 was 74.0 drilling rigs (60%) compared with 58.2 drilling rigs (47%) in the first nine months of 2010. Based on the average utilization of our drilling rigs during the first nine months of 2011, a $100 per day change in dayrates has a $7,400 per day ($2.7 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 those 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 $39.9 million and $28.3 million for the nine months of 2011 and 2010, respectively, from our contract drilling segment and eliminated the associated operating expense of $24.9 million and $23.6 million during the nine months of 2011 and 2010, respectively, yielding $15.0 million and $4.7 million during the nine 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, NGLs 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 nine 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 $355,000 per month ($4.3 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 nine months of 2011 was $4.33 compared to $5.71 for the first nine months of 2010. Based on our first nine months of 2011 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $185,000 per month ($2.2 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $170,000 per month ($2.0 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2011, our average oil price per barrel received, including the effect of hedging, was $86.80 compared with an average oil price, including the effect of hedging, of $67.05 in the first nine months of 2010 and our first nine months of 2011 average NGLs price per barrel received was $43.72 compared with an average NGL price per barrel of $35.91 in the first nine 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 agreement since that determination is based mainly on the value of our oil, NGLs and natural gas reserves. A reduction could limit our ability to carry out our planned capital projects.

Our natural gas production is sold to intrastate and interstate pipelines, 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 nine month increments.

Midstream Operations

This segment 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 910 miles of pipeline. Our operations are located in Oklahoma, Texas, Kansas, Pennsylvania and West Virginia. 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 nine months of 2011 and 2010, this segment purchased $52.5 million and $30.5 million, respectively, of our oil and natural gas segment's production and provided gathering and transportation services to our oil and natural gas segment of $3.5 million and $3.2 million, respectively. Intercompany revenue from services and purchases of production between our midstream segment and our oil and natural gas segment have been eliminated in our unaudited condensed consolidated financial statements.

Our midstream segment gathered an average of 201,788 MMBtu per day in the first nine months of 2011 compared to 182,390 MMBtu per day in the first nine months of 2010. Processed volumes were 102,493 MMBtu per day in the first nine months of 2011 compared to 81,157 MMBtu per day in the first nine months of 2010. The amount of NGLs we sold was 378,585 gallons per day in the first nine months of 2011 compared to 264,679 gallons per day in the first nine months of 2010. Gas gathering volumes per day in the first nine months of 2011 increased 11% compared to the first nine months of 2010 primarily from wells connected to our systems throughout 2011. Processed volumes increased 26% over the comparative nine months and NGLs sold also increased 43% 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 Agreement and Senior Subordinated Notes

In May 2011, we used proceeds from the Notes offering to repay $220.3 million in outstanding debt under our credit agreement. We also terminated two $15.0 million interest rate swaps associated with that debt with a settlement cost to us of $1.5 million.

On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) that replaces our previous credit agreement which was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13, 2016. The amount available to be borrowed is the lesser of the amount we elect as the commitment amount (currently $250.0 million) or the value of the borrowing base as determined by the lenders (currently $600.0 million), but in either event, not to exceed the maximum credit agreement amount of $750.0 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, in connection with this new credit agreement, we paid $1.6 million in origination, agency, syndication and other related fees. We are amortizing these fees over the life of the credit agreement. At September 30, 2011 and October 24, 2011, borrowings were $55.4 million and $72.4 million, respectively.

The lenders under our credit agreement and their respective participation interests are as follows:

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	20.00%
BBVA Compass Bank	20.00%
BMO	16.80%
Bank of America, N.A.	16.80%
Comerica Bank	8.80%
Crédit Agricole	8.80%
BNP Paribas	8.80%
	100.00%

The amount of the borrowing base, which is subject to redetermination on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. 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 agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term 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 term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the 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 September 30, 2011, $50.0 million of our $55.4 million in outstanding borrowings were subject to LIBOR.

We used borrowings under the credit agreement to pay off the commitments issued under our previous credit agreement. In addition, we can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of midstream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes of the Borrowers.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of September 30, 2011, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes

During the second quarter of 2011, we issued $250.0 million of 6.625% Senior Subordinated Notes due May 15, 2021. We used the net proceeds of approximately $244.0 million from the offering to repay our then outstanding debt under our revolving credit agreement and the remaining amount was used for general working capital purposes.

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 horsepower 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 began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now completed and are working in the Bakken shale. Each of these five new drilling rigs is initially working under a two-year drilling contract. During the third quarter of 2011, we were awarded two additional new build rig contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build rigs will initially be working under three year contracts. Delivery of the two rigs is scheduled for the fourth quarter of 2011. Both drilling rigs will be for our Rocky Mountain division operations. On completion of the additional drilling rigs, we will have 128 drilling rigs in our fleet.

Our anticipated 2011 capital expenditures for this segment are $174.0 million. At September 30, 2011, we had commitments to purchase approximately $5.3 million for drill pipe, top drives and related equipment over the next twelve months. We have spent $122.3 million for capital expenditures during the first nine months of 2011 compared to $85.7 million in the first nine 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 119 gross wells (62.20 net wells) in the first nine months of 2011 compared to 105 gross wells (57.33 net wells) in the first nine months of 2010. Total capital expenditures for the first nine months of 2011 by this segment, excluding a $20.9 million ARO liability, and $50.5 million for acquisitions, totaled $370.5 million. Currently we plan to participate in drilling approximately 160 gross wells in 2011 and estimate our total capital expenditures (excluding acquisitions) for this segment are anticipated to be approximately $435.0 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 post closing adjustments. After these adjustments, the acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. This acquisition targeted 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 consisting 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.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper and Ellis Counties in Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The net proved developed reserves associated with the acquisition are estimated at 6.6 Bcfe (91% natural gas) with production of 1.7 MMcfe per day. The acquisition also included in excess of 12,000 net held by production acres in the area for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash, subject to closing adjustments, from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

Midstream 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 expansion of this plant, the total processing capacity at our Hemphill facility has increased to approximately 100.0 MMcf per day. During the third quarter of 2011, we increased the capacity of this plant by 20 MMcf per day by replacing the turbo expander center section.

In our Mid-continent operations, we are in the process of replacing the existing plant on our Cashion system with a high-efficiency gas processing plant. The new plant is expected to be operational during the first quarter of 2012. It will increase our processing capacity and will improve our liquids recovery capability by 12 to 15%. The Cashion plant gathers gas across Logan, Canadian, Oklahoma and Kingfisher Counties in Oklahoma. In the Mississippi Lime play in Grant County, Oklahoma, our new gathering system and processing plant became operational in October. One well is online and three more wells are in the process of being connected. We anticipate an additional 25 to 30 wells to be connected during 2012 due to active drilling by multiple producers in the area around the plant. This is our entrance into the Mississippi Lime play.

In our Appalachian operations, we are in the final stages of completing 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. Currently, we have four wells connected with an expected total initial flow volume in the 8 to 10 MMcf per day range. Three additional wells have been drilled and are waiting on completion prior to being connected. We anticipate this pipeline will be operational during the fourth quarter of 2011. In addition to the Preston County pipeline, we recently signed a letter of intent with a third party to construct a pipeline in Allegheny and Butler Counties of Pennsylvania. First flow of gas from this new system is expected to occur in the fourth quarter of 2011. Expectations are that the first well will flow up to 10 MMcf per day, and we anticipate four more wells to be drilled and connected during the first half of 2012.

During the first nine months of 2011, our midstream segment incurred $59.3 million in capital expenditures as compared to $19.7 million in the first nine months of 2010. For 2011, we have budgeted capital expenditures of approximately $86.0 million.

Contractual Commitments

At September 30, 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)		
Long-term debt (1)	$ 477,034	$ 17,764	$ 35,529	$ 90,929	$ 332,812
Operating leases (2)	4,779	1,615	2,677	487	0
Drill pipe, drilling components and equipment purchases (3)	5,338	5,338	0	0	0
Total contractual obligations	$ 487,151	$ 24,717	$ 38,206	$ 91,416	$ 332,812

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our September 30, 2011 interest rates of 6.625% for the Notes and 2.2% for the credit agreement.

(2) We lease office space or yards in Elmwood, Elk City, Oklahoma City, Quinton 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 $5.3 million of new drilling rig components, drill pipe, drill collars and related equipment over the next twelve months.

At September 30, 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)	$ 2,266	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 6,480	$ 831	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$ 552	$ 552	$ 0	$ 0	$ 0
Asset retirement liability (3)	$ 92,802	$ 2,074	$ 16,840	$ 4,156	$ 69,732
Gas balancing liability (4)	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ 0	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$ 17,921	$ 7,126	$ 3,767	$ 1,296	$ 5,732

(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 Unaudited 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 2011, 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 2011, $22,000 in 2010 and $1,000 in 2009.

(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 agreement 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 agreement. 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. In May 2011, in association with the repayment of outstanding borrowings under our credit agreement, we terminated our two outstanding interest rate swaps that were previously accounted for as cash flow hedges, resulting in an increase of approximately $1.5 million in interest expense. Approximately $1.1 million of that expense was capitalized and is being amortized over the life of the assets.

Commodity Hedges. Our commodity hedging is intended to reduce our exposure 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 third quarter 2011 average daily production, as of September 30, 2011, the approximated percentages of our production that we have hedged are as follows:

Oil and Natural Gas Segment:

	Q4'11	**Q1'12**	**Q2'12**	**Q3'12**	**Q4'12**	**2013**
Daily oil production	59%	67%	67%	67%	67%	30%
Daily natural gas production	58%	33%	33%	33%	33%	0%
Natural gas liquids production	40%	31%	11%	2%	2%	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.

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 September 30, 2011, we determined that there was no material risk of non-performance by our counterparties. At September 30, 2011, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	September 30, 2011
	(In millions)
Bank of Montreal	$ 27.8
BNP Paribas	11.8
Crédit Agricole Corporate and Investment Bank, London Branch	11.0
Comerica Bank	6.1
Bank of America, N.A.	4.1
BBVA Compass Bank	3.7
Macquarie Bank	0.4
BP Corporation	0.3
Barclays Capital	(0.5)
Total assets (liabilities)	$ 64.7

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 September 30, 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $41.3 million and $24.0 million, respectively, and current derivative liabilities of $0.6 million. At September 30, 2010, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $19.4 million and $5.7 million, respectively, and current and non-current derivative liabilities of $0.1 million and $2.6 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 September 30, 2011, we had a gain of $37.3 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at September 30, 2011, we expect to transfer to earnings a gain of approximately $25.0 million, net of tax, of the loss included in accumulated OCI during the next 12 months in the related month of production. The commodity derivative instruments existing as of September 30, 2011 are expected to mature by December 2013.

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 September 30:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In thousands)			
Oil and natural gas revenue:				
Realized gains (losses) on oil and natural gas derivatives	$ 1,814	$ 14,760	$ (1,343)	$ 36,447
Unrealized gains (losses) on ineffectiveness of cash flow hedges	2,336	176	4,158	605
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	128	(427)	(547)	597
Impact on pre-tax earnings	$ 4,278	$ 14,509	$ 2,268	$ 37,649

Stock and Incentive Compensation

During the first nine months of 2011, we granted awards covering 209,150 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 $10.9 million. Compensation expense will be recognized over their two and three year vesting periods, and during the first nine months of 2011, we recognized $2.8 million in additional compensation expense and capitalized $0.7 million for these awards. During the first nine months of 2011, we recognized compensation expense of $7.7 million for all of our restricted stock, stock options and SAR grants and capitalized $1.9 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 nine months of 2011 and 2010, the total we received for all of these fees was $2.4 million and $1.8 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our unaudited 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.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). In May 2011, the FASB issued ASU 2011-04 *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS.* ASU 2011-4 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the Board's intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The update is effective for annual periods beginning after December 15, 2011. We are in the process of evaluating the impact, if any, the adoption of this update will have on our financial statements.

Presentation of Comprehensive Income. In June 2011, the FASB issued ASU 2011-05 – *Presentation of Comprehensive Income.* This ASU amends the Codification to allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. The amendments to the Codification in the ASU do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income.

ASU 2011-05 should be applied retrospectively. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We are in the process of evaluating the option we will choose to present comprehensive income and the impact it will have on our financial statements.

Testing Goodwill for Impairment. In August 2011, the FASB issued ASU 2011-08 – *Intangibles-Goodwill and Other (ASC 350): Testing Goodwill for Impairment.* This ASU is intended to simplify how entities, both public and nonpublic, test goodwill for impairment. ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is "more likely than not" that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in ASC 350, *Intangibles-Goodwill and Other*. The more-likely-than-not threshold is defined as having a likelihood of more than 50%.

ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

Results of Operations

Quarter Ended September 30, 2011 versus Quarter Ended September 30, 2010

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

	Quarter Ended September 30,		Percent
	2011	2010	Change
Total revenue	$ 323,845,000	$ 218,116,000	48%
Net income	$ 53,360,000	$ 34,491,000	55%
Contract Drilling:			
Revenue	$ 128,927,000	$ 85,004,000	52%
Operating costs excluding depreciation	$ 73,004,000	$ 45,406,000	61%
Percentage of revenue from daywork contracts	100%	100%	0%
Average number of drilling rigs in use	78.9	65.4	21%
Average dayrate on daywork contracts	$ 19,309	$ 15,814	22%
Depreciation	$ 20,818,000	$ 18,469,000	13%
Oil and Natural Gas:			
Revenue	$ 134,897,000	$ 96,562,000	40%
Operating costs excluding depreciation, depletion and amortization	$ 29,598,000	$ 27,092,000	9%
Average oil price (Bbl)	$ 86.19	$ 66.94	29%
Average NGL price (Bbl)	$ 45.40	$ 31.67	43%
Average natural gas price (Mcf)	$ 4.39	$ 5.55	(21)%
Oil production (Bbl)	620,000	379,000	64%
NGL production (Bbl)	578,000	378,000	53%
Natural gas production (Mcf)	11,553,000	10,385,000	11%
Depreciation, depletion and amortization rate (Boe)	$ 15.00	$ 12.00	25%
Depreciation, depletion and amortization	$ 47,195,000	$ 30,091,000	57%
Midstream Operations:			
Revenue	$ 60,688,000	$ 37,429,000	62%
Operating costs excluding depreciation and amortization	$ 53,299,000	$ 30,743,000	73%
Depreciation and amortization	$ 4,017,000	$ 3,823,000	5%
Gas gathered—MMBtu/day	228,247	183,161	25%
Gas processed—MMBtu/day	129,820	84,175	54%
Gas liquids sold—gallons/day	449,604	260,519	73%
General and administrative expense	$ 7,800,000	$ 6,637,000	18%
Interest expense, net	$ 1,351,000	$ 0	NM
Income tax expense	$ 33,403,000	$ 21,364,000	56%
Average interest rate	6.1%	3.1%	97%
Average long-term debt outstanding	$ 288,014,000	$ 133,559,000	116%

(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 $43.9 million or 52% in the third quarter of 2011 versus the third quarter of 2010 primarily due to a 21% increase in the average number of drilling rigs in use during the third quarter of 2011 compared to the third quarter of 2010 and a 22% higher average dayrate in the third quarter of 2011 compared to the third quarter of 2010. Average drilling rig utilization increased from 65.4 drilling rigs in the third quarter of 2010 to 78.9 drilling rigs in the third quarter of 2011. Oil prices improved in the third quarter of 2011 compared to the third quarter of 2010, creating increased demand for drilling rigs.

Drilling operating costs increased $27.6 million or 61% between the comparative third quarters of 2011 and 2010 primarily due to increased utilization and increased direct cost due to higher personnel cost. Due to an increase in activity over last year's levels, competition to keep qualified labor has increased. Contract drilling depreciation increased $2.3 million or 13% primarily due to increased utilization and from capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $38.3 million or 40% in the third quarter of 2011 as compared to the third quarter of 2010 primarily due to an increase in equivalent production volumes of 26% and an increase in oil and NGL prices partially offset by decreases in prices for natural gas. Average oil and NGL prices between the comparative quarters increased 29% to $86.19 per barrel and 43% to $45.40 per barrel, respectively, and natural gas prices decreased 21% to $4.39 per Mcf. In the third quarter of 2011, as compared to the third quarter of 2010, oil production increased 64%, NGL production increased 53% and natural gas production increased 11%. Production for third 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 $2.5 million or 9% between the comparative third quarters of 2011 and 2010 due to the increase in total wells and increased production between quarters partially offset by refunds of production taxes attributable to high-cost gas wells received during the third quarter of 2011. Lease operating expenses per Boe decreased 7% to $6.56.

Depreciation, depletion and amortization ("DD&A") increased $17.1 million or 57% primarily due to a 25% increase in our DD&A rate and a 26% increase in equivalent production. The increase in our DD&A rate in the third quarter of 2011 compared to the third quarter of 2010 resulted primarily from increases throughout 2010 and the first nine months 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.

Midstream

Our midstream revenues were $23.3 million or 62% higher for the third quarter of 2011 as compared to the third quarter of 2010 primarily due to higher NGL prices and higher volumes. The average price for NGLs sold increased 29%. Gas processing volumes per day increased 54% between the comparative quarters and NGLs sold per day increased 73% 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 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 25% primarily from new well connections.

Operating costs increased $22.6 million or 73% in the third quarter of 2011 compared to the third quarter of 2010 primarily due to a 25% increase in prices paid for natural gas purchased and increased volumes from new connects. Depreciation and amortization increased $0.2 million, or 5%, primarily due to increased capital investment for system improvements and well connects. For 2011, we increased well connections over 2010 due to increased drilling activity by operators in the areas of our existing gathering systems along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

Other

General and administrative expenses increased $1.2 million or 18% in the third quarter of 2011 compared to the third quarter of 2010 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $1.4 million between the comparative third 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 increased by 97% due to the Notes issued during the second quarter of 2011 and our average debt outstanding was $154.5 million higher in the third quarter of 2011 as compared to the third quarter of 2010 due to the drilling of developmental wells and construction of new rigs in 2011.

Income tax expense increased $12.0 million or 56% in the third quarter of 2011 compared to the third quarter of 2010 primarily due to increased income. Our effective tax rate was 38.5% for the third quarter of 2011 and 38.3% for the third quarter of 2010. Current income tax benefit for the third quarter of 2011 was $3.9 million due to a larger than expected net operating loss carryback recognized in the third quarter of 2011 compared to $8.6 million of total income tax benefit in the third quarter of 2010 due to expected bonus depreciation for 2010. We paid $0.6 million in income taxes during the third quarter of 2011.

Nine Months Ended September 30, 2011 versus Nine Months Ended September 30, 2010

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

	Nine Months Ended September 30, 2011	2010	Percent Change
Total revenue	$ 862,745,000	$ 629,269,000	37 %
Net income	$ 144,206,000	$ 102,819,000	40 %
Contract Drilling:			
Revenue	$ 342,098,000	$ 217,919,000	57 %
Operating costs excluding depreciation	$ 190,086,000	$ 132,847,000	43 %
Percentage of revenue from daywork contracts	100 %	99 %	1 %
Average number of drilling rigs in use	74.0	58.2	27 %
Average dayrate on daywork contracts	$ 18,663	$ 15,037	24 %
Depreciation	$ 57,333,000	$ 48,700,000	18 %
Oil and Natural Gas:			
Revenue	$ 376,393,000	$ 286,751,000	31 %
Operating costs excluding depreciation, depletion and amortization	$ 93,796,000	$ 75,943,000	24 %
Average oil price (Bbl)	$ 86.80	$ 67.05	29 %
Average NGL price (Bbl)	$ 43.72	$ 35.91	22 %
Average natural gas price (Mcf)	$ 4.33	$ 5.71	(24)%
Oil production (Bbl)	1,767,000	1,002,000	76 %
NGL production (Bbl)	1,623,000	1,143,000	42 %
Natural gas production (Mcf)	32,730,000	30,121,000	9 %
Depreciation, depletion and amortization rate (Boe)	$ 14.82	$ 11.34	31 %
Depreciation, depletion and amortization	$ 132,013,000	$ 81,746,000	61 %
Midstream Operations:			
Revenue	$ 144,820,000	$ 114,908,000	26 %
Operating costs excluding depreciation and amortization	$ 119,143,000	$ 92,407,000	29 %
Depreciation and amortization	$ 11,627,000	$ 11,746,000	(1)%
Gas gathered—MMBtu/day	201,788	182,390	11 %
Gas processed—MMBtu/day	102,493	81,157	26 %
Gas liquids sold—gallons/day	378,585	264,679	43 %
General and administrative expense	$ 22,188,000	$ 19,372,000	15 %
Interest expense, net	$ 2,078,000	$ 0	NM
Income tax expense	$ 90,275,000	$ 63,689,000	42 %
Average interest rate	5.6 %	3.8 %	47 %
Average long-term debt outstanding	$ 231,559,000	$ 78,988,000	193 %

(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 $124.2 million or 57% in the first nine months of 2011 versus the first nine months of 2010 primarily due to a 27% increase in the average number of drilling rigs in use during the first nine months of 2011 compared to the first nine months of 2010 and a 24% higher average dayrate in the first nine months of 2011 compared to the first nine months of 2010. Average drilling rig utilization increased from 58.2 drilling rigs in the first nine months of 2010 to 74.0 drilling rigs in the first nine months of 2011. Oil prices improved in the first nine months of 2011 compared to the first nine months of 2010, creating increased demand for drilling rigs.

Drilling operating costs increased $57.2 million or 43% between the comparative nine month periods of 2011 and 2010 primarily due to increased utilization and increased direct 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 $8.6 million or 18% primarily due to increased utilization and from capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $89.6 million or 31% in the first nine months of 2011 as compared to the first nine months of 2010 primarily due to an increase in equivalent production volumes of 23% and an increase in oil and NGL prices partially offset by decreases in prices for natural gas. Average oil and NGL prices between the comparative quarters increased 29% to $86.80 per barrel and 22% to $43.72 per barrel, respectively, while natural gas prices decreased 24% to $4.33 per Mcf. In the first nine months of 2011, as compared to the first nine months of 2010, oil production increased 76%, NGL production increased 42% and natural gas production increased 9%. Oil production increased from our drilling program and from wells acquired over the last twelve months while gas production for the first nine months of 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 $17.9 million or 24% between the comparative nine months of 2011 and 2010 due to increases in lease operating expenses due to increased well servicing costs and higher saltwater disposal fees and higher gross production taxes due to higher oil prices and revenue from increased production between quarters partially offset by refunds of production taxes attributable to high-cost gas wells received during the third quarter of 2011. Lease operating expenses per Boe decreased 1% to $6.64.

Depreciation, depletion and amortization ("DD&A") increased $50.3 million or 61% primarily due to a 31% increase in our DD&A rate and a 23% increase in equivalent production. The increase in our DD&A rate in the first nine months of 2011 compared to the first nine months of 2010 resulted primarily from increased net book value from new reserves added throughout 2010 and in the first nine months of 2011 . 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.

Midstream

Our midstream revenues were $29.9 million or 26% higher for in the first nine months of 2011 as compared to the first nine months of 2010 primarily due to higher NGL volumes and prices. The average price for NGLs sold increased 19%. Gas processing volumes per day increased 26% between the comparative nine months and NGLs sold per day increased 43% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day increased due to 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 11% primarily from new well connections.

Operating costs increased $26.7 million or 29% in the first nine months of 2011 compared to the first nine months of 2010 primarily due to a 13% increase in prices paid for natural gas purchased and a 26% increase in gas purchased per day. Depreciation and amortization decreased $0.1 million, or 1%, primarily due to decreased amortization on our intangible asset. For 2011, we increased well connections over 2010 due to increased drilling activity by operators in the areas of our existing gathering systems along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

Other

Other revenue of $9.7 million for the first nine months of 2010 was primarily attributable to the sale of eight mechanical drilling rigs and the sale of a gas pipeline in which we owned a 60% interest.

General and administrative expenses increased $2.8 million or 15% in the first nine months of 2011 compared to the first nine months of 2010 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $2.1 million between the comparative nine months 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 increased by 47% and our average debt outstanding was $152.6 million higher in the first nine months of 2011 as compared to the first nine months of 2010 due to the drilling of developmental wells and construction of new rigs in 2011.

Income tax expense increased $26.6 million or 42% in the first nine months of 2011 compared to the first nine months of 2010 primarily due to increased income. Our effective tax rate was 38.5% for the first nine months of 2011 and 38.3% for the first nine months of 2010. Current income tax benefit for the first nine months of 2011 was $3.9 million due to a larger than expected net operating loss carryback recognized in the third quarter of 2011 compared with $2.5 million of total income tax benefit for the first nine months of 2010 due to expected bonus depreciation for 2010. We paid $0.6 million in income taxes during the first nine months 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 expressions are used to identify forward-looking statements.

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the number of wells to be drilled or reworked;
- prices for oil, NGLs and natural gas;
- demand for oil, NGLs and natural gas;
- our exploration and drilling prospects;
- the 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;
- the number of 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;
- our ability to timely secure third party services used in completing our wells; and
- our ability to transport or convey our oil and natural gas production to established pipeline systems.

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 nine 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 $355,000 per month ($4.3 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 $185,000 per month ($2.2 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $170,000 per month ($2.0 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.

Oil and Natural Gas Segment:

At September 30, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct'11 – Dec'11	Crude oil – swap	4,000 Bbl/day	$84.28	WTI – NYMEX
Jan'12 – Dec'12	Crude oil – swap	4,500 Bbl/day	$95.91	WTI – NYMEX
Jan'13 – Dec'13	Crude oil – swap	2,000 Bbl/day	$102.05	WTI – NYMEX
Oct'11 – Dec'11	Natural gas – swap	10,000 MMBtu/day	$ 4.43	CEGT
Oct'11 – Dec'11	Natural gas – swap	70,000 MMBtu/day	$ 4.87	IF – NYMEX (HH)
Oct'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	30,000 MMBtu/day	$ 5.05	IF – NYMEX (HH)
Jan'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$ 5.62	IF – PEPL
Oct'11 – Dec'11	Liquids – swap (1)	2,024,418 Gal/mo	$1.07	OPIS – Conway
Oct'11 – Dec'11	Liquids – swap (1)	1,240,068 Gal/mo	$1.00	OPIS – Mont Belvieu
Jan'12 – Mar'12	Liquids – swap (1)	1,350,014 Gal/mo	$1.10	OPIS – Conway
Jan'12 – Mar'12	Liquids – swap (1)	1,155,018 Gal/mo	$0.91	OPIS – Mont Belvieu
Apr'12 – Dec'12	Liquids – swap (1)	180,006 Gal/mo	$2.11	OPIS – Conway
Apr'12 – Jun'12	Liquids – swap (1)	690,028 Gal/mo	$0.79	OPIS – Mont Belvieu

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

At September 30, 2011, the following non-qualifying cash flow derivatives were outstanding:

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

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement debt, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Under our Notes payable, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year, beginning on November 15, 2011).

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 September 30, 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 nine months ended September 30, 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.

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 September 30, 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
July 1, 2011 to July 31, 2011	1,428	$ 61.66	1,428	0
August 1, 2011 to August 31, 2011	19,634	44.32	19,634	0
September 1, 2011 to September 30, 2011	0	0	0	0
Total	21,062	$ 45.50	21,062	0

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the third 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.

Item 6. Exhibits

Exhibits:

10.1	Restricted Stock Award Agreement Form.
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.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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: November 3, 2011

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

Date: November 3, 2011

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