UNIT CORP
Form 10-Q
August 02, 2012
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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2012
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 July 20, 2012, 48,589,062 shares of the issuer's common stock were outstanding.

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Forward-Looking Statements

This document contains “forward-looking statements” within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. All statements, other than statements of historical facts, included in this quarterly report, which address activities, events or developments which we expect or anticipate will or may occur in the future, are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” a similar expressions are used to identify forward-looking statements.

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells 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;
- our plans to maintain or increase 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;
- our ability to transport or convey our oil or natural gas production to established pipeline systems; and
- impact of federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business.

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 that 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 of (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.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2012	December 31, 2011
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,085	$ 835
Accounts receivable, net of allowance for doubtful accounts of $5,343 both at June 30, 2012 and at December 31, 2011	161,496	165,276
Materials and supplies	8,331	8,202
Current derivative asset (Note 9)	42,846	31,938
Current deferred tax asset	10,936	10,936
Prepaid expenses and other	12,177	11,278
Total current assets	236,871	228,465
Property and equipment:		
Drilling equipment	1,467,071	1,423,570
Oil and natural gas properties on the full cost method:		
Proved properties	3,525,177	3,302,032
Undeveloped leasehold not being amortized	208,694	185,632
Gas gathering and processing equipment	337,063	278,919
Transportation equipment	36,620	34,118
Other	44,113	37,544
	5,618,738	5,261,815
Less accumulated depreciation, depletion, amortization and impairment	2,593,153	2,319,484
Net property and equipment	3,025,585	2,942,331
Deferred offering costs	5,375	5,671
Goodwill	62,808	62,808
Other intangible assets, net	1,228	1,855
Non-current derivative asset (Note 9)	9,507	4,514
Other assets	12,063	11,076
Total assets	$ 3,353,437	$ 3,256,720

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

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

	June 30, 2012	December 31, 2011
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 127,794	$ 143,311
Accrued liabilities (Note 4)	55,059	51,733
Income taxes payable	—	781
Contract advances	897	2,055
Current portion of derivative liabilities (Note 9)	—	2,657
Current portion of other long-term liabilities (Note 5)	11,583	12,213
Total current liabilities	195,333	212,750
Long-term debt (Note 5)	332,900	300,000
Non-current derivative liabilities (Note 9)	635	—
Other long-term liabilities (Note 5)	115,727	113,830
Deferred income taxes	708,464	683,123
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 48,589,289 and 48,151,442 shares issued, respectively	9,581	9,541
Capital in excess of par value	417,005	408,109
Accumulated other comprehensive income	30,314	19,026
Retained earnings	1,543,478	1,510,341
Total shareholders' equity	2,000,378	1,947,017
Total liabilities and shareholders' equity	$ 3,353,437	$ 3,256,720

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$146,872	$115,183	$287,778	$213,171
Oil and natural gas	132,553	131,662	266,325	241,496
Gas gathering and processing	49,747	44,368	107,042	84,132
Other	720	282	1,175	101
Total revenues	329,892	291,495	662,320	538,900
Expenses:				
Contract drilling:				
Operating costs	74,819	64,238	150,992	117,082
Depreciation	21,238	19,218	42,566	36,515
Oil and natural gas:				
Operating costs	33,279	33,417	68,888	64,198
Depreciation, depletion and amortization	57,153	44,550	109,350	84,818
Impairment of oil and natural gas properties (Note 2)	115,874	—	115,874	—
Gas gathering and processing:				
Operating costs	42,363	36,789	89,976	65,844
Depreciation and amortization	5,312	3,837	10,446	7,610
General and administrative	8,376	7,496	15,380	14,388
Interest, net	2,542	673	4,368	727
Total operating expenses	360,956	210,218	607,840	391,182
Income (loss) before income taxes	(31,064)	81,277	54,480	147,718
Income tax expense (benefit):				
Current	(2,066)	—	(2,066)	—
Deferred	(9,696)	31,458	23,409	56,872
Total income taxes	(11,762)	31,458	21,343	56,872
Net income (loss)	$(19,302)	$49,819	$33,137	$90,846
Net income (loss) per common share:				
Basic	$(0.40)	$1.05	$0.69	$1.91
Diluted	$(0.40)	$1.04	$0.69	$1.89

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
Net income (loss)	$(19,302)	$49,819	$33,137	$90,846
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $17,256, $10,371, $16,214 and $1,187	27,226	16,796	25,490	1,968
Reclassification - derivative settlements, Net of tax of ($6,106), $1,906, ($9,270) and $1,779	(9,564)	3,045	(14,576)	2,840
Ineffective portion of derivatives, net of tax of ($537), ($1,432), $232 and ($702)	(850)	(2,299)	374	(1,120)
Comprehensive income (loss)	$(2,490)	$67,361	$44,425	$94,534

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

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

	Six Months Ended June 30,	
	2012	2011
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$33,137	$90,846
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	163,140	129,475
Impairment of oil and natural gas properties (Note 2)	115,874	—
Unrealized (gain) loss on derivatives	606	(1,147)
Deferred tax expense	23,409	56,872
Gain on disposition of assets	(1,239)	(158)
Stock compensation plans	7,978	7,026
Other	2,218	1,812
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	1,675	(11,407)
Accounts payable	(28,587)	(26,124)
Material and supplies inventory	(129)	(456)
Accrued liabilities	(993)	6,072
Contract advances	(1,158)	(779)
Other - net	(899)	7,478
Net cash provided by operating activities	315,032	259,510
INVESTING ACTIVITIES:		
Capital expenditures	(371,703)	(343,755)
Producing property and other acquisitions	(2,193)	(9,791)
Proceeds from disposition of assets	6,288	1,604
Net cash used in investing activities	(367,608)	(351,942)
FINANCING ACTIVITIES:		
Borrowings under line of credit	250,500	164,500
Payments under line of credit	(217,600)	(327,500)
Proceeds from issuance of senior subordinated notes, net of offering costs	—	244,035
Proceeds from exercise of stock options	89	644
Book overdrafts	19,837	10,617
Net cash provided by financing activities	52,826	92,296
Net increase (decrease) in cash and cash equivalents	250	(136)
Cash and cash equivalents, beginning of period	835	1,359
Cash and cash equivalents, end of period	$1,085	$1,223

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

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION
The accompanying unaudited condensed consolidated financial statements in this quarterly report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms “company,” “Unit,” “we,” “our,” and “us” refer to Unit Corporation, a Delaware corporation, and, as appropriate, one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires.
The accompanying condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This quarterly report should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 23, 2012, for the year ended December 31, 2011.
In the opinion of our management, the accompanying unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state the following:
• Balance Sheets at June 30, 2012 and December 31, 2011;
• Statements of Operations for the three and six months ended June 30, 2012 and 2011;
• Statements of Comprehensive Income (Loss) for the three and six months ended June 30, 2012 and 2011; and
• Cash Flows for the six months ended June 30, 2012 and 2011.
Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the six months ended June 30, 2012 and 2011 are not necessarily indicative of the results to be realized for the full year in the case of 2012, or that we realized for the full year of 2011.
With respect to the unaudited financial information for the three and six month periods ended June 30, 2012 and 2011 our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated August 2, 2012, 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 is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves based on the unescalated 12-month average price on our oil, natural gas liquids (NGLs), and natural gas adjusted for any cash flow hedges, plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. In the event the unamortized cost of the amortized oil and natural gas properties exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.
During the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our commodity hedges, decreased significantly, resulting in a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record write-downs in future periods.

Our qualifying cash flow hedges used in the ceiling test determination as of June 30, 2012, consisted of swaps covering 2.9 MMBoe in 2012 and 4.5 MMBoe in 2013. The effect of those hedges on the June 30, 2012 ceiling test was a $32.5 million

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pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our oil and natural gas hedging is discussed in Note 9 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

	For the Six Months Ended 6/30/2012
Impairment of oil and gas properties, net of tax	72.1

NOTE 3 – EARNINGS (LOSS) PER SHARE

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

	Income (Loss) (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended June 30, 2012			
Basic earnings (loss) per common share	$(19,302)	47,906	$(0.40)
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	—	—	—
Diluted earnings (loss) per common share	$(19,302)	47,906	$(0.40)
For the three months ended June 30, 2011			
Basic earnings per common share	$49,819	47,655	$1.05
Effect of dilutive stock options, restricted stock and SARs	—	328	(0.01)
Diluted earnings per common share	$49,819	47,983	$1.04

Due to the net loss for the three months ended June 30, 2012, approximately 224,000weighted average shares related to stock options, restricted stock and SARs were antidilutive and were excluded from the earnings per share calculation above. The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended June 30,	
	2012	2011
Stock options and SARs	292,901	49,000
Average Exercise Price	$50.99	$67.83

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	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the six months ended June 30, 2012			
Basic earnings per common share	$33,137	47,868	$0.69
Effect of dilutive stock options, restricted stock and SARs	—	245	—
Diluted earnings per common share	$33,137	48,113	$0.69
For the six months ended June 30, 2011			
Basic earnings per common share	$90,846	47,620	$1.91
Effect of dilutive stock options, restricted stock and SARs	—	324	(0.02)
Diluted earnings per common share	$90,846	47,944	$1.89

	Six Months Ended June 30,	
	2012	2011
Stock options and SARs	250,901	73,500
Average Exercise Price	$52.72	$64.43

NOTE 4 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	June 30, 2012	December 31, 2011
	(In thousands)	
Taxes	$22,724	$13,480
Employee costs	16,460	22,518
Lease operating expenses	7,877	7,346
Interest payable	3,030	2,647
Hedge settlements	—	1,844
Other	4,968	3,898
Total accrued liabilities	$55,059	$51,733

NOTE 5 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

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

	June 30, 2012	December 31, 2011
	(In thousands)	
Credit agreement with average interest rates, of 2.1% and 2.7% at June 30, 2012 and December 31, 2011, respectively	$82,900	$50,000
6.625% senior subordinated notes due 2021	250,000	250,000
Total long-term debt	$332,900	$300,000

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) replacing our previous agreement that was scheduled to mature on May 24, 2012. The credit agreement has a maturity date of September 13,

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2016. The amount available to be borrowed is the lesser of the amount we elect (from time to time) 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. In connection with this new credit agreement, we paid $1.8 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 by the lenders 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 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%. Interest is payable at the end of each month, and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At June 30, 2012, $80.0 million of our $82.9 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 mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

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 June 30, 2012, 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 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 working capital.

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, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. 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 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), and will mature on May 15, 2021.

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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 June 30, 2012.

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Other Long-Term Liabilities
Other long-term liabilities consisted of the following:

	June 30, 2012	December 31, 2011
	(In thousands)	
ARO liability	$96,523	$96,446
Workers' compensation	17,673	17,026
Separation benefit plans	7,250	6,845
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,601	2,463
	127,310	126,043
Less current portion	11,583	12,213
Total other long-term liabilities	$115,727	$113,830

Estimated annual principle payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning July 1, 2012 (and through 2016) are $11.6 million, $22.2 million, $3.8 million, $3.1 million and $85.6 million, respectively.

NOTE 6 – 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 the plugging costs associated with our oil and gas wells.
The following table shows certain information about our AROs for the periods indicated:

	Six Months Ended June 30, 2012		2011	
	(In thousands)			
ARO liability, January 1:	$96,446		$69,265	
Accretion of discount	2,126		1,735	
Liability incurred	4,420		2,879	
Liability settled	(1,447	)	(666	)
Revision of estimates	(5,022	) (1)	9	
ARO liability, June 30:	96,523		73,222	
Less current portion	2,909		1,781	
Total long-term ARO	$93,614		$71,441	

(1) Plugging liability estimates were revised in March 2012 for updates in the cost of services used to plug wells over the preceding year. Although cost per well increased, a slight decrease in the inflation factor resulted in a decrease in estimated cost.

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NOTE 7 – NEW ACCOUNTING PRONOUNCEMENTS

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 FASB'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. Other than modification to disclosure, there was no significant impact 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. 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 chose to present net income and comprehensive income as two consecutive statements in 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 8 – STOCK-BASED COMPENSATION

For the three and six months ended June 30, 2012 , we recognized stock compensation expense for restricted stock awards, stock options, and stock settled SARs of $3.0 million and $5.3 million, respectively. We also capitalized for the same periods stock compensation cost for oil and natural gas properties of $0.7 million and $1.3 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.1 million and $2.0 million, respectively. For the three and six months ended June 30, 2011 , we recognized stock compensation expense for restricted stock awards, stock options, and stock settled SARs of $2.7 million and $5.0 million, respectively. We also capitalized for the same periods stock compensation cost for oil and natural gas properties of $0.7 million and $1.3 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.0 million and $1.9 million, respectively. The remaining unrecognized compensation cost related to unvested awards at June 30, 2012 is approximately $18.0 million of which $3.2 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

At our annual meeting of stockholders held on May 2, 2012, our stockholders approved the Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan). The amended plan allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as non-employee directors. A total of 3,300,000 shares of the Company's stock is authorized for issuance to eligible participants under the amended plan. The amended plan succeeds the Non-employee Directors' 2000 Stock Option Plan (the option plan), and no new awards will be issued under the option plan.

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The table below shows the estimates of the fair value of these stock options granted to our non-employee directors under the option plan in 2011 using the Black-Scholes model and applying the estimated values also presented in the table:

	Six Months Ended June 30, 2011	
Options granted	31,500	
Estimated fair value (in millions)	$0.7	
Estimate of stock volatility	0.48	
Estimated dividend yield	—	%
Risk free interest rate	2	%
Expected annual life based on prior experience	5	
Forfeiture rate	—	%

Expected volatilities are based on the historical volatility of our common stock. Within the model, we use historical data to estimate stock option exercise and termination rates and aggregates groups that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our common 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.

We did not grant any SARs or stock options (other than the non-employee director options discussed above) during either of the three or six month periods ending June 30, 2012 and 2011.
The following table shows the fair value of any restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2012		2011		2012		2011	
Shares granted:								
Employees	—		4,167		367,936		196,748	
Non employee directors	24,606		—		24,606		—	
	24,606		4,167		392,542		196,748	
Estimated fair value (in millions):								
Employees	$—		$0.2		$15.6		$10.3	
Non employee directors	1.0		—		1.0		—	
	$1.0		$0.2		$16.6		$10.3	
Percentage of shares granted expected to be distributed:								
Employees	—	%	95	%	89	%	93	%
Non employee directors	100	%	—	%	100	%	—	%

The restricted stock awards granted during the first three and six months of 2012 and 2011 are being recognized over a three year vesting period, except for a portion of those granted to certain executive officers. As to those executive officers, 30% of the shares granted, or 46,441 shares granted in 2012 and 20,062 shares granted in 2011 (the performance shares), will cliff vest in the first half of 2015 and 2014, respectively. The actual number of performance shares that vest in 2014 and 2015 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 restricted shares granted as performance shares. Based on the first year's results, the participants would receive less than 100% of the performance based shares. Total 2012 awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first six months of 2012 by an aggregate of $3.1 million.

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NOTE 9 – DERIVATIVES
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 June 30, 2012, 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.

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

At June 30, 2012, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'12 – Dec'12	Crude oil – swap	6,250 Bbl/day	$97.72	WTI – NYMEX
Jan'13 – Dec'13	Crude oil – swap	4,000 Bbl/day	$102.68	WTI – NYMEX
Jul'12 – Dec'12	Natural gas – swap	30,000 MMBtu/day	$5.05	IF – NYMEX (HH)
Jul'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$5.62	IF – PEPL
Jul'12 – Sep'12	Natural gas – swap	20,000 MMBtu/day	$2.98	IF – NYMEX (HH)
Jan'13 – Dec'13	Natural gas – swap	30,000 MMBtu/day	$3.44	IF – NYMEX (HH)
Jan'13 – Dec'13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)
Jul'12 – Dec'12	Liquids – swap (1)	180,006 Gal/mo	$2.11	OPIS – Conway
Jul'12 – Dec'12	Liquids – swap (2)	310,000 Gal/mo	$0.69	OPIS – Mont Belvieu

(1)Types of liquids involved are natural gasoline.
(2)Types of liquids involved are ethane.

After June 30, 2012, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Price	Hedged Market
Jan'13 – Dec'13	Crude oil – swap	1,000 Bbl/day	$90.20	WTI – NYMEX
Jan'13 – Dec'13	Natural gas – swap	30,000 MMBtu/day	$3.67	IF – NYMEX (HH)

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

	Balance Sheet Location	Derivative Assets Fair Value June 30, 2012	December 31, 2011
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative asset	$42,846	$31,938
Long-term	Non-current derivative asset	9,507	4,514
Total derivatives designated as hedging instruments		52,353	36,452
Total derivative assets		$52,353	$36,452

	Balance Sheet Location	Derivative Liabilities Fair Value June 30, 2012	December 31, 2011
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current portion of derivative liabilities	$—	$2,657
Long-term	Non-current derivative liabilities	635	—
Total derivatives designated as hedging instruments		635	2,657
Total derivative liabilities		$635	$2,657

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

We recognize in accumulated other comprehensive income (loss) (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 June 30, 2012 and 2011, we had a gain of $30.3 million and a loss of $3.2 million, net of tax, respectively, in accumulated OCI.

Based on market prices at June 30, 2012, we expect to transfer over the next 12 months (in the related month of settlement) a gain of approximately $26.3 million, net of tax, into OCI. The commodity derivative instruments existing as of June 30, 2012 are expected to mature by December 2013.

Certain derivatives do not qualify as cash flow hedges. Currently, all of our derivatives qualify for cash flow treatment; however, during 2011, we had three basis swaps that did not qualify as cash flow hedges. For those types of derivatives, any changes in the fair value that occurred before their maturity (i.e., temporary fluctuations in value) were reported in the unaudited condensed consolidated statements of operations within our oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

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Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statements of Operations (cash flow hedges) for the six months ended June 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2012	2011
	(In thousands)	
Commodity derivatives	$ 30,314	$ (3,163)
Total	$ 30,314	$ (3,163)

(1) Net of taxes.

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statements of Operations (cash flow hedges) for the three months ended June 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2012	2011	2012	2011
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$15,670	$(3,520)	$1,387	$3,731
Interest rate swaps	Interest, net	—	(1,431)	—	—
Total		$15,670	$(4,951)	$1,387	$3,731

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

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

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2012	2011
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$—	$(346)
Total		$—	$(346)

Effect of Derivative Instruments on the Unaudited Condensed Consolidated Statements of Operations (cash flow hedges) for the six months ended June 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2012	2011	2012	2011
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$23,846	$(2,885)	$(606)	$1,822

Interest rate swaps	Interest, net	—	(1,734)	—	—
Total		$23,846	$(4,619)	$(606)	$1,822

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

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

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2012	2011
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ —	$ (947)
Total		$ —	$ (947)

NOTE 10 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value. The highest priority is given to Level 1 and the lowest priority is 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. We corroborate these inputs based on recent transactions and broker quotes and compare with actual settlements.

The following tables set forth our recurring fair value measurements:

	June 30, 2012		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$46,177	$8,951	$55,128
Liabilities	(2,589)	(821)	(3,410)
	$43,588	$8,130	$51,718

	December 31, 2011		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$9,698	$34,321	$44,019
Liabilities	(9,518)	(706)	(10,224)
	$180	$33,615	$33,795

Certain natural gas fixed price swaps were transferred from Level 3 to Level 2 as of June 30, 2012 because of improvements in our ability to obtain and corroborate observable significant inputs to assess the fair value. Our policy is to

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recognize transfers either in or out of fair value hierarchy levels as of the end of the quarterly reporting period in which the event or change in circumstances causing the transfer occurred.

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 and natural gas swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

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

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

	Net Derivatives			
	For the three months ended June 30, 2012		For the six months ended June 30, 2012	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$—	$13,912	$—	$33,615
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	—	5,456	—	16,874
Included in other comprehensive income (loss)	—	(5,687)	—	(3,576)
Settlements	—	(5,551)	—	(16,859)
Transfers out of Level 3 into Level 2	—	—	—	(21,924)
End of period	$—	$8,130	$—	$8,130
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$—	$(95)	$—	$15

(1) Commodity swaps and collars are reported in the unaudited condensed consolidated statements of operations in revenues.

	Net Derivatives			
	For the three months ended June 30, 2011		For the six months ended June 30, 2011	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$(1,361)	$9,368	$(1,614)	$10,868
Total gains or losses (realized and unrealized):				
Included in earnings [(1)]	(1,431)	3,572	(1,734)	7,877
Included in other comprehensive income (loss)	1,361	1,847	1,614	82
Settlements	1,431	(3,038)	1,734	(7,078)
Transfers out of Level 3 into Level 2	—	—	—	—
End of period	$—	$11,749	$—	$11,749
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$—	$534	$—	$799

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

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The following table provides quantitative information about our Level 3 unobservable inputs at June 30, 2012:

	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Commodity contracts (1)	$8,130	Discounted cash flow	Forward commodity price curve	$2.64-$3.22

(1) The commodity contracts detailed in this category include non-exchange-traded natural gas swaps that are valued based on regional pricing other than NYMEX. The forward pricing range represents the low and high price expected to be received within the settlement period.

Based on our valuation at June 30, 2012, we determined that risk of non-performance by 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 June 30, 2012, the carrying values on the unaudited condensed consolidated balance sheets for cash and cash equivalents (classified as Level 1), 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 also considering the risk of our non-performance, long-term debt under our credit agreement at June 30, 2012 approximates its fair value. This debt would be classified as Level 2.

The carrying amount of long-term debt associated with the Notes reported in the unaudited condensed consolidated balance sheet as of June 30, 2012 and December 31, 2011 was $250.0 million. We estimated the fair value of these Notes using quoted marked prices at June 30, 2012 and December 31, 2011 which were $252.8 million and $250.6 million, respectively. These Notes would be classified as Level 2.

NOTE 11 – INDUSTRY SEGMENT INFORMATION

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

- Contract drilling,
- Oil and natural gas, and
- Mid-stream

The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells. The oil and natural gas segment is engaged in the development, acquisition and production of oil and natural gas properties and the mid-stream segment is engaged in the buying, selling, gathering, processing, and treating of natural gas and NGLs. 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 production in Canada is not significant.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
Revenues:				
Contract drilling	$160,925	$129,281	$313,384	$241,789
Elimination of inter-segment revenue	(14,053)	(14,098)	(25,606)	(28,618)
Contract drilling net of inter-segment revenue	146,872	115,183	287,778	213,171
Oil and natural gas	132,553	131,662	266,325	241,496
Gas gathering and processing	65,901	63,894	140,156	120,902
Elimination of inter-segment revenue	(16,154)	(19,526)	(33,114)	(36,770)
Gas gathering and processing net of inter-segment revenue	49,747	44,368	107,042	84,132
Other	720	282	1,175	101
Total revenues	$329,892	$291,495	$662,320	$538,900
Operating income (loss):				
Contract drilling	$50,815	$31,727	$94,220	$59,574
Oil and natural gas	(73,753) (2)	53,695	(27,787) (2)	92,480
Gas gathering and processing	2,072	3,742	6,620	10,678
Total operating income (loss) (1)	(20,866)	89,164	73,053	162,732
General and administrative expense	(8,376)	(7,496)	(15,380)	(14,388)
Interest expense, net	(2,542)	(673)	(4,368)	(727)
Other	720	282	1,175	101
Income (loss) before income taxes	$(31,064)	$81,277	$54,480	$147,718

(1) Total operating income (loss) is total operating revenues less operating expenses, depreciation, depletion, amortization and impairment and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.
(2) In June 2012, we had a non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax).

NOTE 12 – SUBSEQUENT EVENTS

On July 10, 2012, we entered into an agreement to acquire certain oil and natural gas assets from Noble Energy, Inc. (Noble) for $617.1 million in cash, subject to certain possible adjustments. The properties include approximately 84,000 net acres primarily in the Granite Wash, Cleveland, and Marmaton plays in western Oklahoma and the Texas Panhandle. The effective date of this acquisition is April 1, 2012. Closing is anticipated to be in September 2012, subject to customary closing conditions. We intend to finance the acquisition with long-term debt.

In conjunction with the acquisition from Noble we intend to increase the commitments under our existing credit agreement from $250 million ($600 million borrowing base) up to $750 million ($800 million borrowing base).

On July 12, 2012, we priced a private offering to eligible purchasers of $400 million aggregate principal amount of senior subordinated notes (New Notes) due 2021, which will bear interest at a rate of 6.625% per year (the offering). The New Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We closed the offering on July 24, 2012, and intend to use the net proceeds from the offering to partially finance the pending acquisition from Noble. If the Noble acquisition is closed and the required exchange of the recently closed sale of New Notes is made, we anticipate that the newly registered notes will be treated as a single series of debt securities with our previously issued and outstanding $250 million aggregate principal amount of 6.625% senior subordinated notes due 2021. If the Noble acquisition has not been consummated on or before November 30, 2012 or if the agreement between Unit Petroleum Company, the Company and Noble is terminated before that date, the New Notes will be subject to a special mandatory redemption. Depending on whether the special mandatory redemption date occurs on or before or after September 30, 2012, the special mandatory redemption price will be either 98.75% of the aggregate principal amount of the New Notes being redeemed or 99.75% of the aggregate amount of the New Notes being redeemed, in each case, plus accrued and unpaid interest.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of June 30, 2012, and the related condensed consolidated statements of operations and comprehensive income (loss) for the three and six-month periods ended June 30, 2012 and 2011 and the condensed consolidated statements of cash flows for the six-month periods ended June 30, 2012 and 2011. These interim financial statements are the responsibility of the Company's management.

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

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2011, and the related consolidated statements of operations, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 23, 2012, 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, 2011, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
August 2, 2012

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

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

- General;
- Business Outlook;
- Executive Summary;
- Financial Condition and Liquidity;
- New Accounting Pronouncements; and
- 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.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this quarterly report, the success of our consolidated business, as well as that of each of our three operating segments depends, to a large extent, on: the prices we receive for our natural gas, NGLs, and oil production; the demand for oil, NGLs, and natural gas; and, the demand for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. Although all of our current operations (with the exception of a minor amount of production in Canada) are located within the United States, events outside the United States can and do have an impact on us and our industry.

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

Our current 2012 budget for all of our business segments forecasts a 7% increase over our 2011 capital expenditures, excluding acquisitions. Our oil and natural gas segment's capital budget is $457.0 million, a 10% decrease from 2011, excluding acquisitions. Our drilling segment's capital budget is $120.0 million, a 26% decrease from 2011. Our mid-stream segment's capital budget is $224.0 million, a 182% increase over 2011. The increase is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as many new projects including new plants discussed further in the Executive Summary.

In developing our initial overall operating budget for 2012, we used average oil and natural gas prices of $90.00 per Bbl and $3.50 per Mcf. Our budget is subject to possible adjustments for various reasons including changes in commodity prices and industry conditions. We anticipate that our budget will be funded using internally generated cash flow and borrowings under our credit agreement.

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Executive Summary

Contract Drilling

The rate at which our drilling rigs were used ("our utilization rate") for the second quarter 2012 was 60%, compared to 64% and 60% for the first quarter of 2012 and the second quarter of 2011, respectively.

Dayrates for the second quarter of 2012 averaged $20,128, a 1% increase over the first quarter of 2012 and an increase of 7% over the second quarter of 2011. These increases were due primarily to new rigs going into service for which we received a higher rate and for additional equipment added to our 1,000 horsepower rigs which increased their rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the second quarter of 2012 increased 11% over the first quarter of 2012 and 41% over the second quarter of 2011. The increases were primarily due to termination fees for three drilling rigs that were under long-term contracts but were terminated early by the operator during the second quarter of 2012, and to a lesser extent increases in dayrates over the first quarter of 2012 and the second quarter of 2011.

Operating cost per day for the second quarter of 2012 increased 4% over the first quarter of 2012 and increased 13% over the second quarter of 2011. The increases were primarily due to higher indirect costs, yard expenses, and general and administrative expenses.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. However, with the weakened natural gas market, operators are focusing on drilling for oil and NGLs. With this focus operators are also shifting toward drilling in shallower oil plays, like the Mississippian and Permian plays, potentially resulting in a change in the mix of our working drilling rigs. These shallower plays tend to use drilling rigs with lower horsepower which tend to have a lower dayrate and margin. Today, approximately 97% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 96% are drilling horizontal or directional wells.

As of June 30, 2012, we had 39 term drilling contracts with original terms ranging from six months to three years. Twenty-two of these contracts are up for renewal in 2012, 13 in the third quarter and nine in the fourth quarter and 17 are up for renewal in 2013 and later. 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. During the second quarter, we had three drilling rigs that were under long-term contracts that were terminated early by the operator. The early termination fees associated with these contracts total approximately $15.1 million and are included in revenue for the three and six months ended June 30, 2012.

During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party and we placed a new 1,500 horsepower, diesel-electric drilling rig into service, initially working under a three year contract in Wyoming. Additionally, during the second quarter of 2012, we placed another new 1,500 horsepower, diesel-electric drilling rig in North Dakota (also under a three year contract). On deployment of the new drilling rig during the second quarter of 2012, this segment has 128 drilling rigs in its fleet.

As we noted above, our 2012 budget for this segment is $120.0 million, a 26% decrease from 2011.

Oil and Natural Gas

Second quarter 2012 production from our oil and natural gas segment was 3,341,000 barrels of oil equivalent (Boe), a 2% increase over the first quarter of 2012 and a 12% increase over the second quarter of 2011. These increases came primarily from new wells completed in oil and NGL rich prospects and brought online and, to a lesser extent, from production associated with previous acquisitions. Production for the first quarter of 2012 was negatively impacted by approximately 461 MMcfe from the unexpected shut-in of some of our Granite Wash and Wilcox production because of operational issues experienced at third-party facilities associated with that production. Second quarter 2012 oil and NGL production was 44% of our total production compared to 39% of our total production over the second quarter of 2011.

Second quarter 2012 oil and natural gas revenues decreased 1% from the first quarter of 2012 and increased 1% over the second quarter of 2011. The decreases from the first quarter of 2012 were primarily due to decreases in oil, NGL, and natural gas prices. The increases over the second quarter of 2011 were primarily due to increased production offset by decreased NGL and natural gas prices.

Our oil prices for the second quarter of 2012 decreased 4% from the first quarter of 2012 and increased 3% over the second quarter of 2011, respectively. Our NGL and natural gas prices decreased 17% and 10%, respectively, from the first quarter of 2012 and decreased 29% and 30%, respectively, from the second quarter of 2011.

During the second quarter of 2012, we recorded a non-cash ceiling test write down of $115.9 million pre-tax ($72.1

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million, net of tax). If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-downs in future periods.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 1% over both the first quarter of 2012 and the second quarter of 2011. The increases over the respective periods were primarily attributable to increased production and from developmental drilling and acquisitions offset by decreases in prices.

Operating cost per Boe produced for the second quarter of 2012 decreased 8% from the first quarter of 2012 and decreased 11% from the second quarter of 2011. Costs were lower between the second quarter and first quarter of 2012 due to lower per day lease operating expenses. These costs were lower between the second quarter of 2012 and the second quarter of 2011 due primarily to lower gross production taxes resulting from the receipt of tax credits.

For 2012 we hedged approximately 6,100 Bbls per day of oil production and approximately 50,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $97.55 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.09. The average basis differential for the applicable swaps is ($0.28). For 2012 we hedged NGLs of 1,966 Bbls per day in the first quarter, 926 Bbls per day in the second quarter, and 380 Bbls per day in the third and fourth quarters. The NGLs are hedged under swap contracts at an average price of $42.53 per barrel in the first quarter, $41.15 per barrel in the second quarter, $51.28 per barrel in the third quarter, and $50.28 per barrel in the fourth quarter.

Currently for 2013 we have hedged 5,000 Bbls per day of oil production and 80,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $100.19 per barrel. The natural gas production is hedged by swaps for 60,000 Mmbtu per day and a collar for 20,000 Mmbtu per day. The swap transactions were done at a comparable average NYMEX price of $3.56. The collar transaction was done at a comparable average NYMEX floor price of $3.25 and ceiling price of $3.72.

On July 10, 2012, we entered into an agreement to acquire certain oil and natural gas assets from Noble Energy, Inc. (Noble) for $617.1 million in cash, subject to certain possible adjustments. The properties include approximately 84,000 net acres primarily in the Granite Wash, Cleveland, and Marmaton plays in western Oklahoma and the Texas Panhandle. The effective date of this acquisition is April 1, 2012. Closing is anticipated to be in September 2012, subject to customary closing conditions. As of the effective date, the estimated proved reserves of the subject properties is 44.0 MMBoe, and the estimated average daily net production is 10.0 MBoe. The acquisition will add approximately 25,000 net acres to Unit's Granite Wash core area in the Texas Panhandle with significant resource potential including 617 potential horizontal drilling locations. The acreage is characterized by high working interest and operatorship, and 95% of the acreage is held by production. Unit will also receive two natural gas gathering systems as part of the transaction.

For 2012, we plan to participate in the drilling of 160 wells and our capital expenditures budget is $457.0 million (excluding acquisitions). As of June 30, 2012, we completed drilling 93 wells (41.17 net wells). Unit's annual production guidance for 2012, excluding the impact of the Noble acquisition, is approximately 13.2 to 13.5 MMBoe, an increase of 9% to 12% over 2011. Including the anticipated fourth quarter production from the Noble acquisition, Unit estimates its annual production guidance for 2012 to be 14.1 to 14.4 MMBoe, an increase of 17% to 19% over 2011.

Mid-Stream

Second quarter 2012 liquids sold per day increased 20% over the first quarter of 2012 and increased 77% over the second quarter of 2011. The increases were primarily the result of upgrades and expansions to existing plants and the connection of new wells. For the second quarter of 2012, gas processed per day increased 15% from the first quarter of 2012 and increased 96% over the second quarter of 2011. In 2011 and 2012, we upgraded several of our existing processing facilities and added a processing plant which was the primary reason for increased volumes. For the second quarter of 2012, gas gathered per day increased 20% from the first quarter of 2012 and increased 57% over the second quarter of 2011. The increases were primarily from new well connects.

NGL prices in the second quarter of 2012 decreased 28% from the price received in the first quarter of 2012 and 42% from the price received in the second quarter of 2011. Because certain of the contracts used by our mid-stream segment for NGL transactions are percent of proceeds (POP) contracts -- under which we receive a share of the proceeds from the sale of the NGLs--our revenues from those POP contracts fluctuate based on the price of NGLs.

Direct profit (mid-stream revenues less mid-stream operating expense) for the second quarter of 2012 decreased 24% from the first quarter of 2012 and decreased 3% from the second quarter of 2011. The decreases were primarily due to decreases in NGL prices. Total operating cost for our mid-stream segment for the second quarter of 2012 decreased 11% from the first quarter of 2012 due to decreases in price for gas purchased and increased 15% over the second quarter of 2011 due

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primarily to the increase in field direct cost from the expansion of plants.
We have completed the installation of our fifth processing plant in our Hemphill County, Texas facility. We now have the capacity to process 160 MMcf per day of our own and third party Granite Wash natural gas production.
At our Cashion facility, we are continuing to connect new wells to the system and due to this activity, we have installed an additional processing plant. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant has been completed and became operational at the end of March 2012. With the installation of this new plant, our total processing capacity increased to approximately 50 MMcf per day at our Cashion facility.

In the Mississippian play in north central Oklahoma, a new gas gathering system and processing plant in Noble and Kay counties, known as the Bellmon system, was completed and began operating late in the second quarter. This system consists of approximately 10 miles of 12" and 16" pipe with a 10 MMcf per day gas processing plant that will be upgraded to a 30 MMcf per day gas processing plant in the fourth quarter of 2012. We are also planning to connect our existing Remington gathering system to the new Bellmon system. Connecting these two systems will require laying approximately 26 miles of pipeline and installing related compression which is scheduled to be completed by the end of this year. Also at our new Bellmon system, we are planning to extend the system approximately 14 miles to connect to a third-party producer. We anticipate this extension will be completed in the fourth quarter of 2012.

We are continuing to expand operations in the Appalachian region. Construction continues on an additional gathering facility in Allegheny and Butler counties, Pennsylvania, known as the Pittsburgh Mills system. The first phase of this project consists of approximately seven miles of gathering pipeline and a compressor station. Five wells were brought on during the second quarter of 2012. The current gathered volumes are 23 MMcf per day from six wells connected to this system. Construction activity for expansion of this pipeline continues as the producer is maintaining its drilling activity.

Our capital expenditures budget for 2012 is $224.0 million.

Financial Condition and Liquidity
Summary
Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit facility. The principal factors determining the amount of our cash flow are:

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

The following is a summary of certain financial information as of June 30, 2012 and 2011 and for the six months ended June 30, 2012 and 2011:

	June 30, 2012	2011	% Change
	(In thousands except percentages)		
Working capital	$41,538	$43,698	(5)%
Long-term debt	$332,900	$250,000	33 %
Shareholders' equity	$2,000,378	$1,813,258	10 %
Ratio of long-term debt to total capitalization	14 %	12 %	17 %
Net income	$33,137	$90,846	(64)%
Net cash provided by operating activities	$315,032	$259,510	21 %
Net cash used in investing activities	$(367,608)	$(351,942)	4 %
Net cash provided by financing activities	$52,826	$92,296	(43)%

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The following table summarizes certain operating information:

	Six Months Ended June 30, 2012	2011	% Change	
Contract Drilling:				
Average number of our drilling rigs in use during the period	79.1	71.6	10	%
Total number of drilling rigs owned at the end of the period	128	123	4	%
Average dayrate	$19,979	$18,304	9	%
Oil and Natural Gas:				
Oil production (MBbls)	1,506	1,147	31	%
Natural gas liquids production (MBbls)	1,330	1,046	27	%
Natural gas production (MMcf)	22,688	21,178	7	%
Average oil price per barrel received	$94.04	$87.14	8	%
Average oil price per barrel received excluding hedges	$94.53	$96.06	(2	)%
Average NGL price per barrel received	$35.53	$42.80	(17	)%
Average NGL price per barrel received excluding hedges	$34.19	$43.72	(22	)%
Average natural gas price per mcf received	$3.19	$4.29	(26	)%
Average natural gas price per mcf received excluding hedges	$2.18	$3.91	(44	)%
Mid-Stream:				
Gas gathered—MMBtu/day	275,939	188,340	47	%
Gas processed—MMBtu/day	166,116	88,603	87	%
Gas liquids sold—gallons/day	576,089	342,486	68	%
Number of natural gas gathering systems	36	34	6	%
Number of processing plants	11	10	10	%

At June 30, 2012, we had unrestricted cash totaling $1.1 million and had borrowed $82.9 million of the $250.0 million we had elected to then have available under our credit facility. Our credit facility 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 (the 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 facility , which had $220.3 million outstanding as of May 18, 2011. The remaining proceeds were used for general working capital purposes.

On July 10, 2012, we entered into an agreement to acquire certain oil and natural gas assets from Noble for $617.1 million in cash, subject to certain possible adjustments. The effective date of this acquisition is April 1, 2012. Closing is anticipated to be in September 2012, subject to customary closing conditions. We intend to finance the acquisition with long-term debt.

In conjunction with the acquisition from Noble we intend to increase the commitments under our existing credit agreement from $250 million ($600 million borrowing base) up to $750 million ($800 million borrowing base).

On July 12, 2012, we priced a private offering to eligible purchasers of $400 million aggregate principal amount of senior subordinated notes (New Notes) due 2021, which will bear interest at a rate of 6.625% per year (the offering). The New Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We closed the offering on July 24, 2012, and intend to use the net proceeds from the offering to partially finance the pending acquisition from Noble. If the Noble acquisition is closed and the required exchange of the recently closed sale of New Notes is made, we anticipate that the newly registered notes will be treated as a single series of debt securities with our previously issued and outstanding $250 million aggregate principal amount of 6.625% senior subordinated notes due 2021.If the Noble acquisition has not been consummated on or before November 30, 2012 or if the agreement between Unit Petroleum Company, the Company and Noble is terminated before that date, the New Notes will be subject to a special mandatory redemption. Depending on whether the special mandatory redemption date occurs on or before or after

September 30, 2012, the special mandatory redemption price will be either 98.75% of the aggregate principal amount of the New Notes being redeemed or 99.75% of the aggregate amount of the New Notes being redeemed, in each case, plus accrued and unpaid interest.

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Working Capital

Typically, our working capital balance fluctuates primarily because of the timing of our trade accounts receivable and accounts payable and from the fluctuation in current assets and liabilities associated with the mark to market value of our hedging activity. We had working capital of $41.5 million and $43.7 million as of June 30, 2012 and 2011, respectively. The effect of our hedging activity increased working capital by $26.3 million as of June 30, 2012 and decreased working capital by $3.2 million as of June 30, 2011.

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.

In the first quarter 2011, we increased compensation for drilling personnel in all our divisions. As a result of continued competition to keep qualified labor, we again increased compensation for rig personnel in the Rockies Division during the first quarter of 2012.

With the weakened natural gas market, operators are focusing on drilling for oil and NGLs. With this focus operators are also shifting toward drilling in shallower oil plays, like the Mississippian and Permian plays, potentially resulting in a change in the mix of our working drilling rigs. These shallower plays tend to use drilling rigs with lower horsepower which tend to have a lower dayrate and margin. 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 six months of 2012, our average dayrate was $19,979 per day compared to $18,304 per day for the first six months of 2011. The average number of our drilling rigs used in the first six months of 2012 was 79.1 drilling rigs (62%) compared with 71.6 drilling rigs (59%) in the first six months of 2011. Based on the average utilization of our drilling rigs during the first six months of 2012, a $100 per day change in dayrates has a $7,910 per day ($2.9 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our oil and natural gas segment. Depending on the timing of the services, some of the drilling services we perform on our properties are deemed to be associated with the acquisition of an ownership interest in the property. Accordingly, revenues and expenses for those drilling services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $25.6 million and $28.6 million for the six months of 2012 and 2011, respectively, from our contract drilling segment and eliminated the associated operating expense of $16.7 million and $18.5 million during the six months of 2012 and 2011, respectively, yielding $8.9 million and $10.1 million during the six months of 2012 and 2011, 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, NGLs, 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 six months of 2012 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 $364,000 per month ($4.4 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 six months of 2012 was $3.19 compared to $4.29 for the first six months of 2011. Based on our first six months of 2012 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $239,000 per month ($2.9 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 $211,000 per month ($2.5 million annualized) change in our pre-tax operating cash flow. In the first six months of 2012, our average oil price per barrel received, including the effect of hedging, was $94.04 compared with an average oil price, including the effect of hedging, of $87.14 in the first six months of 2011 and our first six months of 2012 average NGLs price per barrel received, including the effect of hedging, was $35.53 compared with an average NGL price per barrel of $42.80 in the first six months of 2011.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to the lower of unamortized cost or a ceiling. The ceiling is defined as 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, 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. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion, and amortization expense in future periods. Once incurred, a write-down cannot be reversed.

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. At June 30, 2012, the 12-month average unescalated prices were $95.67 per barrel of oil, $56.04 per barrel of NGLs, and $3.15 per Mcf of natural gas, adjusted for price differentials. The unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGL, and natural gas reserves. As a result, we recorded a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). If there are further declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-downs in future periods.

Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our credit facility since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

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

Mid-Stream Operations

Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries. Superior is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas and operates three natural gas treatment plants, 11 processing plants, 36 gathering systems and 981 miles of pipeline. Superior operates 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 six months of 2012 and 2011, our mid-stream operations purchased $31.1 million and $34.6 million, respectively, of our oil and natural gas segment's production and provided gathering and transportation services to the oil and natural gas segment of $2.0 million and $2.2 million, respectively. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our condensed consolidated financial statements.

Our mid-stream segment gathered an average of 275,939 MMBtu per day in the first six months of 2012 compared to 188,340 MMBtu per day in the first six months of 2011. Processed volumes were 166,116 MMBtu per day in the first six months of 2012 compared to 88,603 MMBtu per day in the first six months of 2011. The amount of NGLs we sold was 576,089 gallons per day in the first six months of 2012 compared to 342,486 gallons per day in the first six months of 2011. Gas gathering volumes per day in the first six months of 2012 increased 47% compared to the first six months of 2011 primarily from the 62 wells connected to our systems throughout 2011 compared to 52 wells connected throughout 2010. Processed volumes increased 87% over the comparative six months and NGLs sold also increased 68% 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

Credit Agreement. On September 13, 2011, we entered into a Senior Credit Agreement (credit agreement) replacing our previous agreement that 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 (from time to time) 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. In connection with this new credit agreement, we paid $1.8 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. At June 30, 2012 and July 20, 2012, borrowings were $82.9 million and $148.9 million, respectively.

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On July 10, 2012, we entered into an agreement to acquire certain oil and natural gas assets from Noble for $617.1 million in cash, subject to certain possible adjustments. The effective date of this acquisition is April 1, 2012. Closing is anticipated to be in September 2012, subject to customary closing conditions. We intend to finance the acquisition with long-term debt.

In conjunction with the acquisition from Noble we intend to increase the commitments under our existing credit agreement from $250 million ($600 million borrowing base) up to $750 million ($800 million borrowing base)

The current 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	%
Wells Fargo Bank, National Association	8.80	%
	100.00	%

The amount of the borrowing base, which is subject to redetermination by the lenders 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 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%. Interest is payable at the end of each month, and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At June 30, 2012, $80.0 million of our $82.9 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 mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

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 June 30, 2012, 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 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

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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 working capital.

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, subject to certain automatic customary releases, including sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, exercise of legal defeasance option or covenant defeasance option, and designation of a subsidiary guarantor as unrestricted in accordance with the Indenture. 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 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), 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 June 30, 2012.

On July 12, 2012, we priced a private offering to eligible purchasers of $400 million aggregate principal amount of New Notes due 2021, which will bear interest at a rate of 6.625% per year. The New Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We closed the offering on July 24, 2012, and intend to use the net proceeds from the offering to partially finance the pending acquisition from Noble. If the Noble acquisition is closed and the required exchange of the recently closed sale of New Notes is made, we anticipate that the newly registered notes will be treated as a single series of debt securities with our previously issued and outstanding $250 million aggregate principal amount of 6.625% senior subordinated notes due 2021. If the Noble acquisition has not been consummated on or before November 30, 2012 or if the agreement between Unit Petroleum Company, the Company and Noble is terminated before that date, the New Notes will be subject to a special mandatory redemption. Depending on whether the special mandatory redemption date occurs on or before or after September 30, 2012, the special mandatory redemption price will be either 98.75% of the aggregate principal amount of the New Notes being redeemed or 99.75% of the aggregate amount of the New Notes being redeemed, in each case, plus accrued and unpaid interest.

Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. All of these drilling rigs are now working in the Bakken shale in North Dakota under two-year drilling contracts.

During the third quarter of 2011, we were awarded two additional new build contracts for 1,500 horsepower, diesel-electric drilling rigs. These new build drilling rigs are initially working under three year contracts. One was placed into service during the fourth quarter of 2011 and the other was placed into service during the first quarter of 2012.

During the fourth quarter of 2011, we entered into an agreement to build a new 1,500 horsepower, diesel-electric drilling rig which was placed into service in North Dakota in the second quarter of 2012. This new build drilling rig is initially working under a three year contract. During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. We currently have 128 drilling rigs in our fleet.

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Our 2012 capital expenditures budget for this segment is $120.0 million. At June 30, 2012, we had commitments to purchase approximately $1.5 million for new drilling rig components over the next twelve months. We have spent $53.2 million for capital expenditures during the first six months of 2012 compared to $85.0 million in the first six months of 2011.

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 93 gross wells (41.17 net wells) in the first six months of 2012 compared to 79 gross wells (37.49 net wells) in the first six months of 2011. Total capital expenditures for the first six months of 2012 by this segment, excluding a $2.0 million credit to producing properties for ARO liability adjustments and $2.2 million for acquisitions, totaled $246.9 million. Currently we plan to participate in drilling approximately 160 gross wells in 2012 and our total capital expenditures budget (excluding acquisitions) for this segment is approximately $457.0 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.

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 acres held by production which are available 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.

During the fourth quarter of 2011, we leased approximately 60,000 net acres of undeveloped oil and gas leasehold located in south central Kansas for approximately $17.3 million.

After June 30, 2012, we entered into an agreement to acquire certain oil and natural gas assets from Noble for $617.1 million in cash, subject to certain possible adjustments. The properties include approximately 84,000 net acres primarily in the Granite Wash, Cleveland, and Marmaton plays in western Oklahoma and the Texas Panhandle. The effective date of this acquisition is April 1, 2012. Closing is anticipated to be in September 2012, subject to customary closing conditions.

Mid-Stream Acquisitions and Capital Expenditures. We have completed the installation of our fifth processing plant in our Hemphill County, Texas facility. We now have the capacity to process 160 MMcf per day of our own and third party Granite Wash natural gas production.

At our Cashion facility, we are continuing to connect new wells to the system and due to this activity, we have installed an additional processing plant. The installation of the new 25 MMcf per day high efficiency turbo-expander processing plant has been completed and became operational at the end of March 2012. With the installation of this new plant, our total processing capacity increased to approximately 50 MMcf per day at our Cashion facility.

In the Mississippian play in north central Oklahoma, a new gas gathering system and processing plant in Noble and Kay counties, known as the Bellmon system, was completed and began operating late in the second quarter. This system consists of approximately 10 miles of 12” and 16” pipe with a 10 MMcf per day gas processing plant that will be upgraded to a 30 MMcf per day gas processing plant in the fourth quarter of 2012. We are also planning to connect our existing Remington gathering system to the new Bellmon system. Connecting these two systems will require laying approximately 26 miles of pipeline and installing related compression which is scheduled to be completed by the end of this year. Also at our new Bellmon system, we are planning to extend the system approximately 14 miles to connect to a third-party producer. We anticipate this extension will be completed in the fourth quarter of 2012.

We are continuing to expand operations in the Appalachian region. Construction continues on an additional gathering facility in Allegheny and Butler counties, Pennsylvania, known as the Pittsburgh Mills system. The first phase of this project consists of approximately seven miles of gathering pipeline and a compressor station. Five wells were brought on during the second quarter of 2012. The current gathered volumes are 23 MMcf per day from six wells connected to this system.

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Construction activity for expansion of this pipeline continues as the producer is maintaining its drilling activity.

During the first six months of 2012, our mid-stream segment incurred $58.6 million in capital expenditures as compared to $36.8 million in the first six months of 2011. For 2012, we have budgeted capital expenditures of approximately $224.0 million.

Contractual Commitments
At June 30, 2012, 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)	$495,271	$18,270	$36,541	$118,084	$322,376
Operating leases (2)	15,287	9,673	5,084	500	30
Drill pipe, drilling components and equipment purchases (3)	1,500	1,500	—	—	—
Total contractual obligations	$512,058	$29,443	$41,625	$118,584	$322,406

(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 June 30, 2012 interest rates of 6.625% for the Notes and 2.1% for the credit agreement.

(2) We lease office space or yards in Elmwood, Elk City, Oklahoma City and Tulsa, Oklahoma; Canadian and Houston, Texas; Denver and Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through September, 2017. 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 $1.5 million of new drilling rig components over the next twelve months.

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At June 30, 2012, 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)	$2,601	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$7,250	$486	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$635	$—	$635	$—	$—
Asset retirement liability (3)	$96,523	$2,909	$22,979	$4,605	$66,030
Gas balancing liability (4)	$3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$17,673	$8,188	$3,050	$1,225	$5,210

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

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

(3) When a well is drilled or acquired, under "Accounting for Asset Retirement Obligations," we record the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

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

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 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 $43,000 in 2012 and $22,000 in both 2011 and 2010.

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

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Derivative Activities

Periodically we enter into hedge transactions covering part of the interest rate payable under our credit facility as well as the prices to be received for a portion of our oil, NGLs, and natural gas production.

Interest Rate Swaps. From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit 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. Currently, we do not have any interest rate swaps.

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 second quarter 2012 average daily production, the approximated percentages of our production that we have hedged are as follows:

	Q3’12		Q4’12		2013	
Daily oil production	72	%	72	%	58	%
Daily natural gas production	52	%	36	%	65	%
Natural gas liquids production	5	%	5	%	—	%

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 June 30, 2012, we determined that the risk of non-performance by our counterparties was not material. . At June 30, 2012, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	June 30, 2012 (In millions)
Bank of Montreal	$24.3
Comerica Bank	7.7
BNP Paribas	7.4
Crédit Agricole Corporate and Investment Bank, London Branch	6.4
Bank of America, N.A.	2.5
BBVA Compass Bank	2.2
Macquarie Bank	0.9
BP Corporation	0.3
Total assets (liabilities)	$51.7

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 June 30, 2012, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $42.8 million and $9.5 million, respectively and non-current derivative liabilities of $0.6 million. At December 31, 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $31.9 million and $4.5 million, respectively, and current derivative liabilities of $2.7 million.

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 June 30, 2012, we had a gain of $ 30.3 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at June 30, 2012, we expect to transfer to earnings a gain of approximately $26.3 million, net of tax, of the income included in accumulated OCI during the next 12 months in the related month of production. The commodity derivative instruments existing as of June 30, 2012 are expected to mature by December 2013.

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Certain derivatives do not qualify for designation as cash flow hedges. Currently, we do not have any derivatives that do not qualify as cash flow hedges. For derivatives that do not qualify, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported as unrealized gains (losses) in the consolidated statements of operations within our oil and natural gas revenues. 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. The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at June 30:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
Increases (decreases) in:				
Revenue:				
Realized gains (losses) on derivatives	$15,670	$(3,610)	$23,846	$(3,157)
Unrealized losses on ineffectiveness of cash flow hedges	1,387	3,731	(606)	1,822
Unrealized losses on non-qualifying derivatives	—	(256)	—	(675)
Total increase (decrease) in revenues due to derivatives	$17,057	$(135)	$23,240	$(2,010)

Stock and Incentive Compensation

During the first six months of 2012, we granted awards covering 392,542 shares of restricted stock to employees and non-employee directors. The employee awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $16.6 million. Compensation expense will be recognized over the three year vesting periods, and during the first six months of 2012, we recognized $2.5 million in additional compensation expense and capitalized $0.6 million for these awards. During the first six months of 2012, we recognized compensation expense of $5.3 million for all of our restricted stock, stock options and SAR grants and capitalized $1.3 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 to $1.5 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 six months of 2012 and 2011, the total we received for all of these fees was $0.7 million and $1.4 million, respectively. Our proportionate share of assets, liabilities and net income (loss) relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

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New Accounting Pronouncements

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 FASB'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. Other than modification to disclosure, there was no significant impact 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. 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 chose to present net income and comprehensive income as two consecutive statements in 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.

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Results of Operations

Quarter Ended June 30, 2012 versus Quarter Ended June 30, 2011

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

	Quarter Ended June 30,		Percent
	2012	2011	Change
Total revenue	$329,892,000	$291,495,000	13 %
Net income (loss)	$(19,302,000)	$49,819,000	(139)%
Contract Drilling:			
Revenue	$146,872,000	$115,183,000	28 %
Operating costs excluding depreciation	$74,819,000	$64,238,000	16 %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	76.7	73.1	5 %
Average dayrate on daywork contracts	$20,128	$18,861	7 %
Depreciation	$21,238,000	$19,218,000	11 %
Oil and Natural Gas:			
Revenue	$132,553,000	$131,662,000	1 %
Operating costs excluding depreciation, depletion and amortization	$33,279,000	$33,417,000	— %
Average oil price (Bbl)	$92.43	$89.77	3 %
Average NGL price (Bbl)	$32.34	$45.49	(29)%
Average natural gas price (Mcf)	$3.03	$4.30	(30)%
Oil production (Bbl)	786,000	591,000	33 %
NGL production (Bbl)	674,000	567,000	19 %
Natural gas production (Mcf)	11,287,000	10,946,000	3 %
Depreciation, depletion and amortization rate (Boe)	$16.92	$14.82	14 %
Depreciation, depletion and amortization	$57,153,000	$44,550,000	28 %
Impairment of oil and natural gas properties	$115,874,000	$—	NM
Mid-Stream:			
Revenue	$49,747,000	$44,368,000	12 %
Operating costs excluding depreciation and amortization	$42,363,000	$36,789,000	15 %
Depreciation and amortization	$5,312,000	$3,837,000	38 %
Gas gathered—MMBtu/day	300,602	190,921	57 %
Gas processed—MMBtu/day	177,407	90,737	96 %
Gas liquids sold—gallons/day	629,350	356,484	77 %
General and administrative expense	$8,376,000	$7,496,000	12 %
Interest expense, net	$2,542,000	$673,000	NM
Income tax expense (benefit)	$(11,762,000)	$31,458,000	(137)%
Average interest rate	5.6 %	7.0 %	(20)%
Average long-term debt outstanding	$327,642,000	$230,141,000	42 %

(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 $31.7 million or 28% in the second quarter of 2012 versus the second quarter of 2011. The increase was primarily due to a 5% increase in the average number of drilling rigs in use during the second quarter of 2012 as compared to the second quarter of 2011 and a 7% higher average dayrate in the second quarter of 2012 compared to the second quarter of 2011. Average drilling rig utilization increased from 73.1 drilling rigs in the second quarter of 2011 to 76.7 drilling

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rigs in the second quarter of 2012. With oil prices being favorable compared to low natural gas prices, there was increased demand for drilling rigs throughout 2011 to drill for liquids; however, with continuing low natural gas prices and declining NGL prices, we are starting to see a decrease in drilling activity. During the second quarter of 2012, we had three drilling rigs that were under long-term contracts that were terminated early by the operator. The early termination fees associated with these contracts are approximately $15.1 million.

Drilling operating costs increased $10.6 million or 16% between the comparative second quarters of 2012 and 2011. This increase was primarily due to increased utilization, higher direct cost due to increased payroll, supplies and maintenance expense, and increased indirect cost due to higher personnel benefit cost. In the first quarter 2011, we increased compensation for drilling personnel in all our divisions. We again increased compensation for rig personnel in our Rockies Division during the first quarter of 2012. Contract drilling depreciation increased $2.0 million or 11% primarily due to capital expenditures for new rigs constructed during 2011, upgrades to existing drilling rigs in our fleet and from increased utilization.

Oil and Natural Gas

Oil and natural gas revenues increased $0.9 million or 1% in the second quarter of 2012 as compared to the second quarter of 2011 primarily due to an increase in equivalent production volumes of 12% and an increase in oil prices. The positive impact of the increase production was somewhat offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative quarters increased 3% to $92.43 per barrel, NGL prices decreased 29% to $32.34 per barrel, and natural gas prices decreased 30% to $3.03 per Mcf. In the second quarter of 2012, as compared to the second quarter of 2011, oil production increased 33%, NGL production increased 19% and natural gas production increased 3%. 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 previous acquisitions.

Oil and natural gas operating costs decreased $0.1 million between the comparative second quarters of 2012 and 2011 due to lower gross production taxes offset by increases in lease operating expenses primarily from increased workover, saltwater disposal fees and compression and dehydration expense. Lease operating expenses per Boe decreased 3% to $6.25.

Depreciation, depletion and amortization (“DD&A”) increased $12.6 million or 28% primarily due to a 14% increase in our DD&A rate and a 12% increase in equivalent production. The increase in our DD&A rate in the second quarter of 2012 compared to the second quarter of 2011 resulted primarily from increases throughout 2011 and the first six months of 2012 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.

During the second quarter of 2012, we recorded a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). If there are further 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.

Mid-Stream

Our mid-stream revenues were $5.4 million or 12% higher for the second quarter of 2012 as compared to the second quarter of 2011 primarily due to higher NGL volumes sold offset by lower prices. Gas processing volumes per day increased 96% between the comparative quarters and NGLs sold per day increased 77% 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 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 57% primarily from well connections. The average price for natural gas sold decreased 51% and the average price for NGLs sold decreased 42%.

Operating costs increased $5.6 million or 15% in the second quarter of 2012 compared to the second quarter of 2011 primarily due to a 83% increase in the per day gas volumes purchased somewhat offset by a 47% decrease in prices paid for natural gas purchased. Depreciation and amortization increased $1.5 million, or 38%, primarily due to increased assets entered into service throughout 2011 and 2012. For 2012, we anticipate further benefit of the additional processing capacity from the Hemphill facility and an increase in well connections over 2011 due to anticipated drilling activity by operators in the areas of our existing gathering systems.

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Other

General and administrative expenses increased $0.9 million or 12% in the second quarter of 2012 compared to the second quarter of 2011 primarily due to increases in the number of employees and increased employee costs.

Interest expense, net of capitalized interest, increased $1.9 million between the comparative second quarters of 2012 and 2011. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate decreased from 7.0% to 5.6% and our average debt outstanding was $97.5 million higher in the second quarter of 2012 as compared to the second quarter of 2011 due to acquisitions in the oil and natural gas segment during the second half of 2011 and construction of new rigs and mid-stream plants.

Income tax expense (benefit) changed from an expense of $31.5 million in the second quarter of 2011 to a benefit of $11.8 million in the second quarter of 2012 due to the non-cash ceiling test write-down mentioned above. Our effective tax rate was 37.9% for the second quarter of 2012 and 38.7% for the second quarter of 2011. There was no current income tax expense for the second quarter of 2011 and a $2.1 million benefit in the second quarter of 2012. We paid $1.9 million of income taxes in the second quarter of 2012.

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Six Months Ended June 30, 2012 versus Six Months Ended June 30, 2011
Provided below is a comparison of selected operating and financial data:

	Six Months Ended June 30,		Percent
	2012	2011	Change
Total revenue	$662,320,000	$538,900,000	23 %
Net income	$33,137,000	$90,846,000	(64)%
Contract Drilling:			
Revenue	$287,778,000	$213,171,000	35 %
Operating costs excluding depreciation	$150,992,000	$117,082,000	29 %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	79.1	71.6	10 %
Average dayrate on daywork contracts	$19,979	$18,304	9 %
Depreciation	$42,566,000	$36,515,000	17 %
Oil and Natural Gas:			
Revenue	$266,325,000	$241,496,000	10 %
Operating costs excluding depreciation, depletion and amortization	$68,888,000	$64,198,000	7 %
Average oil price (Bbl)	$94.04	$87.14	8 %
Average NGL price (Bbl)	$35.53	$42.80	(17)%
Average natural gas price (Mcf)	$3.19	$4.29	(26)%
Oil production (Bbl)	1,506,000	1,147,000	31 %
NGL production (Bbl)	1,330,000	1,046,000	27 %
Natural gas production (Mcf)	22,688,000	21,178,000	7 %
Depreciation, depletion and amortization rate (Boe)	$16.38	$14.70	11 %
Depreciation, depletion and amortization	$109,350,000	$84,818,000	29 %
Impairment of oil and natural gas properties	$115,874,000	$—	NM
Mid-Stream:			
Revenue	$107,042,000	$84,132,000	27 %
Operating costs excluding depreciation and amortization	$89,976,000	$65,844,000	37 %
Depreciation and amortization	$10,446,000	$7,610,000	37 %
Gas gathered—MMBtu/day	275,939	188,340	47 %
Gas processed—MMBtu/day	166,116	88,603	87 %
Gas liquids sold—gallons/day	576,089	342,486	68 %
General and administrative expense	$15,380,000	$14,388,000	7 %
Interest expense, net	$4,368,000	$727,000	NM
Income tax expense	$21,343,000	$56,872,000	(62)%
Average interest rate	5.7 %	5.2 %	10 %
Average long-term debt outstanding	$315,864,000	$202,863,000	56 %

(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 $74.6 million or 35% in the first six months of 2012 versus the first six months of 2011 primarily due to a 10% increase in the average number of drilling rigs in use during the first six months of 2012 compared to the first six months of 2011 and a 9% higher average dayrate in the first six months of 2012 compared to the first six months of 2011. Average drilling rig utilization increased from 71.6 drilling rigs in the first six months of 2011 to 79.1 drilling rigs in the first six months of 2012. With oil prices being favorable compared to low natural gas prices, there was increased demand for drilling rigs throughout 2011 to drill for liquids; however, with low natural gas prices and declining NGL prices, we are starting to see a decrease in drilling activity. During the first six months of 2012, we had four drilling rigs that were under contracts that were terminated early by the operator. The early termination fees associated with these contracts are approximately $15.8 million.

Drilling operating costs increased $33.9 million or 29% between the comparative first six months of 2012 and 2011 primarily due to increased utilization, higher direct cost due to increased payroll, supplies and maintenance expense and increased indirect cost due to higher personnel benefit cost. As activity increased over last year's levels, competition to keep qualified labor also increased. In the first quarter 2011, we increased compensation for drilling personnel in all our divisions. As a result of continued competition to keep qualified labor, we again increased compensation for rig personnel in the Rockies Division during the first quarter of 2012. Contract drilling depreciation increased $6.1 million or 17% primarily due to capital expenditures for new rigs constructed during 2011, upgrades to existing drilling rigs in our fleet and from increased utilization.

Oil and Natural Gas

Oil and natural gas revenues increased $24.8 million or 10% in the first six months of 2012 as compared to the first six months of 2011 primarily due to an increase in equivalent production volumes of 16% and an increase in oil prices somewhat offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative six month periods increased 8% to $94.04 per barrel, NGL prices decreased 17% to $35.53 per barrel and natural gas prices decreased 26% to $3.19 per Mcf. In the first six months of 2012, as compared to the first six months of 2011, oil production increased 31%, NGL production increased 27% and natural gas production increased 7%. 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 previous acquisitions.

Oil and natural gas operating costs increased $4.7 million or 7% between the comparative first six months of 2012 and 2011 due to increases in lease operating expenses primarily from increased workover, saltwater disposal fees and compression and dehydration expense partially offset by lower gross production taxes. Lease operating expenses per Boe decreased 2% to $6.56.

DD&A increased $24.5 million or 29% primarily due to an 11% increase in our DD&A rate and a 16% increase in equivalent production. The increase in our DD&A rate in the first six months of 2012 compared to the first six months of 2011 resulted primarily from increases throughout 2011 and the first six months of 2012 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.

During the second quarter of 2012, we recorded a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). If there are further 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.

Mid-Stream

Our mid-stream revenues were $22.9 million or 27% higher for the first six months of 2012 as compared to the first six months of 2011 primarily due to higher NGL volumes sold offset by lower prices. Gas processing volumes per day increased 87% between the comparative six months and NGLs sold per day increased 68% between the comparative six months. 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 47% between the comparative six months primarily from well connections. The average price for natural gas sold decreased 44% and the average price for NGLs sold decreased 28% between the comparative six month periods.

Operating costs increased $24.1 million or 37% in the first six months of 2012 compared to the first six months of 2011 primarily due to a 77% increase in the per day gas volumes purchased somewhat offset by a 34% decrease in prices paid for natural gas purchased. Depreciation and amortization increased $2.8 million, or 37%, primarily due to increased assets entered into service throughout 2011 and 2012. For 2012, we anticipate further benefit of the additional processing capacity from the Hemphill facility and an increase in well connections over 2011 due to anticipated drilling activity by operators in the areas of our existing gathering systems.

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Other

General and administrative expenses increased $1.0 million or 7% in the first six months of 2012 compared to the first six months of 2011 primarily due to increases in the number of employees and increased employee costs.

Interest expense, net of capitalized interest, increased $3.6 million between the comparative first six months of 2012 and 2011. 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 from 5.2% to 5.7% and our average debt outstanding was $113.0 million higher in the first six months of 2012 as compared to the first six months of 2011 due to the issuance of $250.0 million of Senior Subordinated Notes during the second quarter of 2011 and due to acquisitions in the oil and natural gas segment during second half of 2011 and construction of new rigs and mid-stream plants.

Income tax expense decreased $35.5 million or 62% due to the non-cash ceiling test write-down mentioned above. Our effective tax rate was 39.2% for the first six months of 2012 and 38.5% for the first six months of 2011. There was no current income tax expense for the first six months of 2011 and a $2.1 million benefit in the first six months of 2012. We paid $1.9 million of income taxes in the first six months of 2012.

Safe Harbor Statement

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

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

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the 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;

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- 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 six months 2012 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 $364,000 per month ($4.4 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 $239,000 per month ($2.9 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 $211,000 per month ($2.5 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. We do not hold or issue derivative instruments for speculative trading purposes.

At June 30, 2012, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'12 – Dec'12	Crude oil – swap	6,250 Bbl/day	$97.72	WTI – NYMEX
Jan'13 – Dec'13	Crude oil – swap	4,000 Bbl/day	$102.68	WTI – NYMEX
Jul'12 – Dec'12	Natural gas – swap	30,000 MMBtu/day	$5.05	IF – NYMEX (HH)
Jul'12 – Dec'12	Natural gas – swap	15,000 MMBtu/day	$5.62	IF – PEPL
Jul'12 – Sep'12	Natural gas – swap	20,000 MMBtu/day	$2.98	IF – NYMEX (HH)
Jan'13 – Dec'13	Natural gas – swap	30,000 MMBtu/day	$3.44	IF – NYMEX (HH)
Jan'13 – Dec'13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)
Jul'12 – Dec'12	Liquids – swap (1)	180,006 Gal/mo	$2.11	OPIS – Conway
Jul'12 – Dec'12	Liquids – swap (2)	310,000 Gal/mo	$0.69	OPIS – Mont Belvieu

(1)Types of liquids involved are natural gasoline.
(2)Types of liquids involved are ethane.

After June 30, 2012, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Price	Hedged Market

Jan’13 – Dec’13	Crude oil – swap	1,000 Bbl/day	$90.20	WTI – NYMEX
Jan’13 – Dec’13	Natural gas – swap	30,000 MMBtu/day	$3.67	IF – NYMEX (HH)

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Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, 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, 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).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of June 30, 2012 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended June 30, 2012 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, 2011. 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 quarterly 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, 2011, which could materially affect our business, financial condition, or future results. The risks described below and 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.

Except as set forth below, 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, 2011.

Events in the financial markets and the economy could adversely affect our operations and financial condition.

As a result of volatility in oil and natural gas prices and substantial uncertainty in the capital markets due to the uncertain global economic environment, a number of our drilling customers have reduced spending on exploration and development drilling. In addition, it is uncertain whether customers, vendors, and/or suppliers will be able to access financing necessary to sustain their operations, fulfill their commitments, or fund future operations and obligations. The uncertainty in the global economic environment may result in a decrease in demand for drilling rigs. These conditions could have a material adverse effect on our business, financial condition and results of operations.

We may decide not to drill some of the prospects we have identified, and locations that we do drill may not yield oil, natural gas and NGL in commercially viable quantities.

Our oil and natural gas segment's prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, natural gas, and NGL prices, the generation of additional seismic or geological information, and other factors, we may decide not to drill one or more of these prospects. As a result, we may not be able to increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial position, and results of operations. In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions,

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proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. At December 31, 2011, we had 121 proved undeveloped drilling locations. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of those reserves could also have a negative effect on the borrowing base under our credit facility.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, NGLs, and natural gas to be commercially viable after drilling, operating and other costs.

The borrowing base under our credit facility is determined semi-annually at the discretion of the lenders and is based in a large part on the prices for oil, NGLs, and natural gas.

Significant declines in oil, NGLs, and natural gas prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and therefore the borrowings permitted to be outstanding under our credit facility. If outstanding borrowings are in excess of the borrowing base, we must (a) repay the loan in excess of the borrowing base, (b) dedicate additional properties to the borrowing base, or (c) begin monthly principal payments in accordance with our credit agreement.

New legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Environmental Protection Agency (the “EPA”) has commenced a study of the potential environmental impacts of hydraulic fracturing, including its impact on drinking water sources and public health, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states, including some in which we operate such as Texas and Wyoming, have adopted and others are considering adopting regulations that could restrict hydraulic fracturing, regulate waste disposal and require disclosure of the chemicals used in hydraulic fracturing. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, each of which could adversely affect our business and/or cumulatively impact our business and could also result in additional burdens that could serve to delay or limit the drilling services we provide to third parties whose drilling operations could be impacted by these regulations or increase our costs of compliance and doing business as well as delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

On April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production from hydraulic fracturing, including new “green completions” of hydraulically fractured wells by 2015, and certain natural gas processing operations. In addition to new requirements for upstream producers, the rules also establish specific new requirements, effective in 2012, for emissions from various equipment. These rules may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which, in turn, may directly or indirectly adversely impact our business, financial condition and results of operations.

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

The following table provides information relating to our repurchase of common stock for the three months ended June 30, 2012:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2012 to April 30, 2012	7,214	$42.76	7,214	—
May 1, 2012 to May 31, 2012	—	—	—	—
June 1, 2012 to June 30, 2012	—	—	—	—
Total	7,214	$42.76	7,214	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the second quarter 2012 vesting for grants previously made from our “Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012.”

(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. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits
Exhibits:

10.1	Form of Unit Corporation Restricted Stock Award Agreement for Non-Employee Directors
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.

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SIGNATURES

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

	Unit Corporation
Date: August 2, 2012	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: August 2, 2012	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer