UNIT CORP
Form 10-Q
November 01, 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 September 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 October 22, 2012, 48,565,039 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)

	September 30, 2012	December 31, 2011
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,023	$ 835
Accounts receivable, net of allowance for doubtful accounts of $5,343 both at September 30, 2012 and at December 31, 2011	160,666	165,276
Materials and supplies	10,151	8,202
Current derivative asset (Note 10)	14,517	31,938
Current deferred tax asset	10,936	10,936
Prepaid expenses and other	12,791	11,278
Total current assets	210,084	228,465
Property and equipment:		
Drilling equipment	1,469,511	1,423,570
Oil and natural gas properties on the full cost method:		
Proved properties	3,641,786	3,302,032
Undeveloped leasehold not being amortized	578,803	185,632
Gas gathering and processing equipment	398,810	278,919
Transportation equipment	37,487	34,118
Other	53,278	37,544
	6,179,675	5,261,815
Less accumulated depreciation, depletion, amortization and impairment	2,660,250	2,319,484
Net property and equipment	3,519,425	2,942,331
Debt issuance cost	13,767	5,671
Goodwill	62,808	62,808
Other intangible assets, net	934	1,855
Non-current derivative asset (Note 10)	1,948	4,514
Other assets	12,117	11,076
Total assets	$ 3,821,083	$ 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

	September 30, 2012	December 31, 2011
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 145,362	$ 143,311
Accrued liabilities (Note 5)	82,709	51,733
Income taxes payable	2,002	781
Contract advances	5,110	2,055
Current portion of derivative liabilities (Note 10)	851	2,657
Current portion of other long-term liabilities (Note 6)	11,413	12,213
Total current liabilities	247,447	212,750
Long-term debt (Note 6)	645,154	300,000
Non-current derivative liabilities (Note 10)	1,214	—
Other long-term liabilities (Note 6)	164,170	113,830
Deferred income taxes	734,122	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, 48,565,428 and 48,151,442 shares issued, respectively	9,591	9,541
Capital in excess of par value	419,409	408,109
Accumulated other comprehensive income	9,912	19,026
Retained earnings	1,590,064	1,510,341
Total shareholders' equity	2,028,976	1,947,017
Total liabilities and shareholders' equity	$ 3,821,083	$ 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 INCOME (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$133,420	$128,927	$421,198	$342,098
Oil and natural gas	131,420	134,897	397,745	376,393
Gas gathering and processing	52,935	60,688	159,977	144,820
Other	(15)	(667)	1,160	(566)
Total revenues	317,760	323,845	980,080	862,745
Expenses:				
Contract drilling:				
Operating costs	72,988	73,004	223,980	190,086
Depreciation	20,094	20,818	62,660	57,333
Oil and natural gas:				
Operating costs	36,147	29,598	105,035	93,796
Depreciation, depletion and amortization	44,489	47,195	153,839	132,013
Impairment of oil and natural gas properties (Note 2)	—	—	115,874	—
Gas gathering and processing:				
Operating costs	46,267	53,299	136,243	119,143
Depreciation and amortization	5,884	4,017	16,330	11,627
General and administrative	8,434	7,800	23,814	22,188
Interest, net	7,087	1,351	11,455	2,078
Total operating expenses	241,390	237,082	849,230	628,264
Income before income taxes	76,370	86,763	130,850	234,481
Income tax expense (benefit):				
Current	2,516	(3,949)	450	(3,949)
Deferred	27,268	37,352	50,677	94,224
Total income taxes	29,784	33,403	51,127	90,275
Net income	$46,586	$53,360	$79,723	$144,206
Net income per common share:				
Basic	$0.97	$1.12	$1.66	$3.03
Diluted	$0.97	$1.11	$1.66	$3.01

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Net income	$46,586	$53,360	$79,723	$144,206
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of ($8,838), $27,015, $7,377 and $28,201	(14,137)	43,154	11,353	45,123
Reclassification - derivative settlements, Net of tax of ($5,523), ($771), ($14,793) and $1,008	(8,720)	(1,232)	(23,296)	1,608
Ineffective portion of derivatives, net of tax of $1,560, ($899), $1,792 and ($1,601)	2,455	(1,437)	2,829	(2,557)
Comprehensive income	$26,184	$93,845	$70,609	$188,380

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)

	Nine Months Ended September 30, 2012	2011
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$79,723	$144,206
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	234,350	201,924
Impairment of oil and natural gas properties (Note 2)	115,874	—
Unrealized (gain) loss on derivatives	4,621	(3,611)
Deferred tax expense	50,677	94,224
(Gain) loss on disposition of assets	(1,283)	462
Stock compensation plans	12,271	10,780
Other	3,376	2,740
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	4,516	(26,118)
Accounts payable	(11,753)	(30,439)
Material and supplies	(1,949)	(1,780)
Accrued liabilities	20,140	13,487
Contract advances	3,055	(1,190)
Other - net	(1,478)	13,166
Net cash provided by operating activities	512,140	417,851
INVESTING ACTIVITIES:		
Capital expenditures	(584,858)	(541,044)
Producing property and other acquisitions (Note 3)	(600,321)	(50,525)
Proceeds from disposition of assets (Note 3)	296,582	7,779
Net cash used in investing activities	(888,597)	(583,790)
FINANCING ACTIVITIES:		
Borrowings under line of credit	543,700	334,100
Payments under line of credit	(593,700)	(441,700)
Proceeds from issuance of senior subordinated notes, net of debt issuance cost	386,274	243,950
Proceeds from exercise of stock options	90	644
Book overdrafts	40,281	28,746
Net cash provided by financing activities	376,645	165,740
Net increase (decrease) in cash and cash equivalents	188	(199)
Cash and cash equivalents, beginning of period	835	1,359
Cash and cash equivalents, end of period	$1,023	$1,160

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 September 30, 2012 and December 31, 2011;
• Statements of Income for the three and nine months ended September 30, 2012 and 2011;
• Statements of Comprehensive Income for the three and nine months ended September 30, 2012 and 2011; and
• Cash Flows for the nine months ended September 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 nine months ended September 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 nine month periods ended September 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 November 1, 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, NGLs, 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.
For the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly, resulting in a non-cash ceiling test write down of $115.9 million pre-tax ($72.1 million, net of tax). 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 pre-tax increase in the discounted net cash flows of our oil and natural gas

properties.

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At September 30, 2012 the 12-month average commodity prices, including the discounted value of our cash flow hedges, were at levels that did not require us to take a write-down of our oil and natural gas properties. If there are further declines in the 12-month average prices, including the discounted value of our cash flow hedges, we may be required to record a write-down in future periods.

Our qualifying cash flow hedges used in the ceiling test determination as of September 30, 2012, consisted of swaps covering 1.3 MMBoe in 2012 and 6.9 MMBoe in 2013. The effect of those hedges on the September 30, 2012 ceiling test was a $38.4 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our oil, NGL, and natural gas hedging is discussed in Note 10 of the Notes to our Unaudited Condensed Consolidated Financial Statements.

NOTE 3 – ACQUISITIONS AND DIVESTITURES

Year to Date 2012 Acquisitions

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble Energy, Inc. (Noble). The acquisition includes approximately 84,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The amount paid at closing was $594.5 million. The effective date of the Noble acquisition was April 1, 2012. As of the effective date the estimated proved reserves of the acquired properties were 44 million barrels of oil equivalent (MMBoe). The acquisition adds approximately 25,000 net acres to our Granite Wash core area in the Texas Panhandle with significant resource potential including approximately 600 horizontal drilling locations. The total acreage acquired in western Oklahoma is approximately 59,000 net acres and is characterized by high working interest and operatorship, 95% of which is held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

The Noble acquisition is accounted for using the acquisition method under ASC 805, Business Combinations, which requires that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed. It is based on information available to us at the time these unaudited condensed consolidated financial statements were prepared. We believe these estimates are reasonable; however, the estimates are subject to change as additional information becomes available and is assessed by us (in thousands):

Preliminary Purchase Price	
Total consideration given	$594,463
Preliminary Allocation of Purchase Price	
Oil and natural gas properties included in the full cost pool:	
Proved oil and natural gas properties	$260,798
Undeveloped oil and natural gas properties	355,180
Total oil and natural gas properties included in the full cost pool (1)	615,978
Equipment and facilities	25,163
Asset retirement obligation	(46,678)
Fair value of net assets acquired	$594,463

(1) We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates.

Pro Forma Financial Information

The following unaudited pro forma financial information is presented to reflect the operations of the acquired assets as if the acquisition had been completed on January 1, 2012 and 2011, respectively. The unaudited pro forma financial information was derived from the historical accounting records of the seller adjusted for estimated transaction costs, depreciation, depletion and amortization, ceiling test impact, general and administrative expenses, capitalized interest, and interest on the $400.0 million of bonds issued along with additional borrowings under our credit facility to finance the acquisition. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of our expected future results of operations.

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The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the acquisition or any estimated costs that will be incurred to integrate these assets. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands, except per share data)			
Pro forma:				
Revenues	$335,394	$354,320	$1,041,350	$964,165
Net income	$47,186	$60,897	$140,670	$171,445
Net income per common share:				
Basic	$0.98	$1.28	$2.94	$3.60
Diluted	$0.98	$1.27	$2.92	$3.58

Year to Date 2012 Divestitures

We completed the following divestitures to-date in 2012, all of which were accounted for as adjustments to the full cost pool with no gain or loss recognized:

- In September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses were $226.6 million.
- In September 2012, we sold certain oil and natural gas assets located in Brazos and Madison counties of Texas, for approximately $44.1 million.

Other

In conjunction with the acquisition and divestitures completed in the third quarter 2012, we took the necessary steps to secure like-kind exchange tax treatment for the transactions under Section 1031 of the Internal Revenue Code.

NOTE 4 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended September 30, 2012			
Basic earnings per common share	$46,586	47,938	$0.97
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	—	263	—
Diluted earnings per common share	$46,586	48,201	$0.97
For the three months ended September 30, 2011			
Basic earnings per common share	$53,360	47,687	$1.12
Effect of dilutive stock options, restricted stock and SARs	—	281	(0.01)
Diluted earnings per common share	$53,360	47,968	$1.11

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The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended September 30,	
	2012	2011
Stock options and SARs	278,901	149,665
Average Exercise Price	$51.57	$58.41

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the nine months ended September 30, 2012			
Basic earnings per common share	$79,723	47,891	$1.66
Effect of dilutive stock options, restricted stock and SARs	—	215	—
Diluted earnings per common share	$79,723	48,106	$1.66
For the nine months ended September 30, 2011			
Basic earnings per common share	$144,206	47,642	$3.03
Effect of dilutive stock options, restricted stock and SARs	—	290	(0.02)
Diluted earnings per common share	$144,206	47,932	$3.01

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

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	September 30, 2012	December 31, 2011
	(In thousands)	
Employee costs	$18,941	$22,518
Divestiture related costs	18,246	—
Interest payable	17,148	2,647
Taxes	14,211	13,480
Lease operating expenses	8,566	7,346
Hedge settlements	343	1,844
Other	5,254	3,898
Total accrued liabilities	$82,709	$51,733

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NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES
Long-Term Debt
As of the dates in the table, long-term debt consisted of the following:

	September 30, 2012	December 31, 2011
	(In thousands)	
Credit agreement with an average interest rate of 2.7% at December 31, 2011	$—	$50,000
6.625% senior subordinated notes due 2021, net of unamortized discount of $4.8 million at September 30, 2012	645,154	250,000
Total long-term debt	$645,154	$300,000

Credit Agreement. On September 5, 2012, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on 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 (amended to $500.0 million from $250.0 million) or the value of the borrowing base as determined by the lenders (amended to $800.0 million from $600.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million (amended from $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 amendment, we paid $1.5 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 September 30, 2012, we did not have any outstanding borrowings under our credit facility.
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 September 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 2011 Notes). The 2011 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

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amortized as debt issuance cost over the life of the 2011 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 2011 Notes were registered under the Securities Act.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of senior subordinated notes (the 2012 Notes) due May 15, 2021, which will bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance the acquisition of oil and natural gas properties from Noble. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes. The 2012 Notes were not registered under the Securities Act.

Under the registration rights agreement filed with the SEC on Form 8-K on July 25, 2012, we are going to offer to exchange the 2012 Notes for additional notes of our existing 2011 Notes, which are registered under the Securities Act and have terms substantially identical to those of the 2012 Notes. After the exchange is completed, the 2012 Notes that are tendered (the Exchanged Notes) will be treated as a single series of debt securities with the 2011 Notes bringing the total to $650.0 million aggregate principal amount of 6.625% senior subordinated notes if all the 2012 Notes are tendered. The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the notes will mature on May 15, 2021.

The 2011 Notes and the 2012 Notes are, and the Exchange Notes will be, 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 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 their respective Indentures described below. 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 2011 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 2011 Notes (as supplemented, the 2011 Indenture). The 2012 Notes were issued under an Indenture dated as of July 24, 2012 between us, the Guarantors and the Trustee, as supplemented by the First Supplemental Indenture dated as of July 24, 2012, establishing the terms and providing for the issuance of the 2012 Notes (as supplemented, the 2012 Indenture). The discussion of the 2011 Notes and the 2012 Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture and the 2012 Indenture, respectively.

On and after May 15, 2016, we may redeem all or, from time to time, a part of the 2011 Notes, 2012 Notes, or Exchanged Notes (collectively, 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 2011 Indenture and the 2012 Indenture contain customary events of default. The Indentures governing the Notes contain covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2012.

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

	September 30, 2012	December 31, 2011
	(In thousands)	
Asset retirement obligation (ARO) liability	$144,849	$96,446
Workers' compensation	17,267	17,026
Separation benefit plans	7,484	6,845
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,720	2,463
	175,583	126,043
Less current portion	11,413	12,213
Total other long-term liabilities	$164,170	$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 October 1, 2012 (and through 2016) are $11.4 million, $23.0 million, $8.4 million, $4.5 million and $3.5 million, respectively.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

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

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

	Nine Months Ended September 30, 2012	2011
	(In thousands)	
ARO liability, January 1:	$96,446	$69,265
Accretion of discount	3,215	2,598
Liability incurred	52,306 (1)	12,674
Liability settled	(1,606)	(831)
Liability sold	(1,258)	—
Revision of estimates	(4,254) (2)	9,096
ARO liability, September 30:	144,849	92,802
Less current portion	2,857	2,074
Total long-term ARO	$141,992	$90,728

(1) The liability incurred increased $46.7 million related to the Noble properties acquired in September 2012.

(2) 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. Costs were again reviewed in September 2012 resulting in no change to the March 2012 estimates.

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NOTE 8 – 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 9 – STOCK-BASED COMPENSATION

For the three and nine months ended September 30, 2012 , we recognized stock compensation expense for restricted stock awards of $2.9 million and $8.2 million, respectively. For the same period we also capitalized stock compensation cost for oil and natural gas properties of $0.7 million and $2.0 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.2 million and $3.2 million, respectively. For the three and nine months ended September 30, 2011 , we recognized stock compensation expense for restricted stock awards and stock options of $2.7 million and $7.7 million, respectively. We also capitalized for the same periods stock compensation cost for oil and natural gas properties of $0.6 million and $1.9 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $1.1 million and $3.0 million, respectively. The remaining unrecognized compensation cost related to unvested awards at September 30, 2012 is approximately $14.5 million of which $2.6 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 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 common 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:

	Nine Months Ended September 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 nine month periods ending September 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 September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
Shares granted:								
Employees	2,509		12,402		370,445		209,150	
Non employee directors	—		—		24,606		—	
	2,509		12,402		395,051		209,150	
Estimated fair value (in millions):								
Employees	$0.1		$0.6		$15.7		$10.9	
Non employee directors	—		—		1.0		—	
	$0.1		$0.6		$16.7		$10.9	
Percentage of shares granted expected to be distributed:								
Employees	95	%	95	%	94	%	93	%
Non employee directors	—	%	—	%	100	%	—	%

The restricted stock awards granted during the first three and nine 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 in 2012 and 20,062 shares 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 resulted in stock compensation expense and the capitalized cost related to oil and natural gas properties for the first nine months of 2012 by an aggregate of $5.6 million.

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NOTE 10 – 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 September 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.

We have documented policies and procedures to monitor and control the use of derivative instruments. We do not engage in derivative transactions for speculative purposes. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. Therefore, the change in fair value, on all commodity derivatives entered into after that determination, will be reflected in the income statement and not in accumulated other comprehensive income (OCI).

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

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct’12 – Dec’12	Crude oil – swap	6,250 Bbl/day	$97.72	WTI – NYMEX
Jan’13 – Dec’13	Crude oil – swap	5,500 Bbl/day	$99.71	WTI – NYMEX
Oct’12 – Dec’12	Natural gas – swap	30,000 MMBtu/day	$5.05	IF – NYMEX (HH)
Oct’12 – Dec’12	Natural gas – swap	15,000 MMBtu/day	$5.62	IF – PEPL
Jan’13 – Dec’13	Natural gas – swap	60,000 MMBtu/day	$3.56	IF – NYMEX (HH)
Jan’13 – Dec’13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)
Oct’12 – Dec’12	Liquids – swap (1)	180,006 Gal/mo	$2.11	OPIS – Conway
Oct’12 – Dec’12	Liquids – swap (2)	310,000 Gal/mo	$0.67	OPIS – Mont Belvieu

(1)Types of liquids involved are natural gasoline.

(2)Types of liquids involved are ethane.

After September 30, 2012, we entered into the following non-designated hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan’13 – Dec’13	Natural gas – swap	20,000 MMBtu/day	$3.94	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 September 30, 2012 (In thousands)	December 31, 2011
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative asset	$14,517	$31,938
Long-term	Non-current derivative asset	1,948	4,514
Total derivatives designated as hedging instruments		16,465	36,452
Total derivative assets		$16,465	$36,452

	Balance Sheet Location	Derivative Liabilities Fair Value September 30, 2012 (In thousands)	December 31, 2011
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current portion of derivative liabilities	$851	$2,657
Long-term	Non-current derivative liabilities	1,214	—
Total derivatives designated as hedging instruments		2,065	2,657
Total derivative liabilities		$2,065	$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.

For derivative transactions entered into before October 2012, we recognize in accumulated OCI the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of September 30, 2012 and 2011, we had a gain of $9.9 million and $37.3 million, net of tax, respectively, in accumulated OCI.

Based on market prices at September 30, 2012, we expect to transfer over the next 12 months (in the related month of settlement) a gain of approximately $8.3 million, net of tax, into OCI. The commodity derivative instruments existing as of September 30, 2012 are expected to mature by December 2013.

Certain derivatives do not qualify as cash flow hedges. As of September 30, 2012, 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 income 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 income (cash flow hedges) for the nine months ended September 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2012	2011
	(In thousands)	
Commodity derivatives	$ 9,912	$ 37,323
Total	$ 9,912	$ 37,323

(1) Net of taxes.

Effect of derivative instruments on the unaudited condensed consolidated statements of income (cash flow hedges) for the three months ended September 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2012	2011	2012	2011
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$14,243	$2,003	$(4,015)	$2,336
Interest rate swaps	Interest, net	—	—	—	—
Total		$14,243	$2,003	$(4,015)	$2,336

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

Effect of derivative instruments on the condensed consolidated statements of income (derivatives not designated as hedging instruments) for the three months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2012	2011
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$—	$(61)
Total		$—	$(61)

Effect of derivative instruments on the unaudited condensed consolidated statements of income (cash flow hedges) for the nine months ended September 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2012	2011	2012	2011
		(In thousands)			
	Oil and natural gas revenue	$38,088	$(882)	$(4,621)	$4,158

Commodity derivatives					
Interest rate swaps	Interest, net	—	(1,734)	—	—
Total		$38,088	$(2,616)	$(4,621)	$4,158

(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 income (derivatives not designated as hedging instruments) for the nine months ended September 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2012	2011
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ —	$ (1,008)
Total		$ —	$ (1,008)

NOTE 11 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value. 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:

	September 30, 2012		
	Level 2	Level 3	Total
	(In thousands)		
Financial assets (liabilities):			
Commodity derivatives:			
Assets	$21,851	$4,007	$25,858
Liabilities	(9,054)	(2,404)	(11,458)
	$12,797	$1,603	$14,400

	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 March 31, 2012 because of improvements in our ability to obtain and corroborate observable significant inputs to assess the fair value. Our policy is to 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.

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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 September 30, 2012		For the nine months ended September 30, 2012	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$—	$8,130	$—	$33,615
Total gains or losses (realized and unrealized):				
Included in earnings [1]	—	2,241	—	19,114
Included in other comprehensive income (loss)	—	(4,194)	—	(7,770)
Settlements	—	(4,574)	—	(21,432)
Transfers out of Level 3 into Level 2	—	—	—	(21,924)
End of period	$—	$1,603	$—	$1,603
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$—	$(2,333)	$—	$(2,318)

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

	Net Derivatives			
	For the three months ended September 30, 2011		For the nine months ended September 30, 2011	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps
	(In thousands)			
Beginning of period	$—	$11,749	$(1,614)	$10,868
Total gains or losses (realized and unrealized):				
Included in earnings [1]	—	4,046	(1,734)	11,923
Included in other comprehensive income (loss)	—	13,182	1,614	13,264
Settlements	—	(3,848)	1,734	(10,926)
Transfers out of Level 3 into Level 2	—	—	—	—
End of period	$—	$25,129	$—	$25,129
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$—	$198	$—	$997

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

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

	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Commodity swaps (1)	$3,835	Discounted cash flow	Forward commodity price curve	$2.76-$3.50
Commodity collars (2)	$(2,232)	Discounted cash flow	Forward commodity price curve	$0.07-$0.72

(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.

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

Based on our valuation at September 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 September 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 September 30, 2012 approximates its fair value. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount, associated with the Notes reported in the unaudited condensed consolidated balance sheet as of September 30, 2012 and December 31, 2011 were $645.2 million and $250.0 million, respectively. We estimated the fair value of these Notes using quoted marked prices at September 30, 2012 and December 31, 2011 which were $674.4 million and $250.6 million, respectively. These Notes would be classified as Level 2.

NOTE 12 – INDUSTRY SEGMENT INFORMATION

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

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

The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells. The oil and natural gas segment is engaged in the development, acquisition, and production of oil, NGLs, 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Revenues:				
Contract drilling	$145,561	$140,193	$458,945	$381,982
Elimination of inter-segment revenue	(12,141)	(11,266)	(37,747)	(39,884)
Contract drilling net of inter-segment revenue	133,420	128,927	421,198	342,098
Oil and natural gas	131,420	134,897	397,745	376,393
Gas gathering and processing	70,394	79,919	210,550	200,821
Elimination of inter-segment revenue	(17,459)	(19,231)	(50,573)	(56,001)
Gas gathering and processing net of inter-segment revenue	52,935	60,688	159,977	144,820
Other	(15)	(667)	1,160	(566)
Total revenues	$317,760	$323,845	$980,080	$862,745
Operating income:				
Contract drilling	$40,338	$35,105	$134,558	$94,679
Oil and natural gas	50,784	58,104	22,997 (2)	150,584
Gas gathering and processing	784	3,372	7,404	14,050
Total operating income (1)	91,906	96,581	164,959	259,313
General and administrative expense	(8,434)	(7,800)	(23,814)	(22,188)
Interest expense, net	(7,087)	(1,351)	(11,455)	(2,078)
Other	(15)	(667)	1,160	(566)
Income before income taxes	$76,370	$86,763	$130,850	$234,481

(1) Total operating income 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).

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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 September 30, 2012, and the related condensed consolidated statements of income and comprehensive income for the three and nine-month periods ended September 30, 2012 and 2011 and the condensed consolidated statements of cash flows for the nine-month periods ended September 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 income, 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
November 1, 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.
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.

Executive Summary
Contract Drilling
The rate at which our drilling rigs were used ("our utilization rate") for the third quarter 2012 was 57%, compared to 60% and 63% for the second quarter of 2012 and the third quarter of 2011, respectively.
Dayrates for the third quarter of 2012 averaged $19,989, a 1% decrease from the second quarter of 2012 and an increase of 4% over the third quarter of 2011. The decrease from the second quarter 2012 is due primarily to the terminated contracts

having higher rates. The increase over the third quarter of 2011 was due primarily to new rigs going into service for which we received a higher rate, increased demand for drilling rigs in the 1,000 horsepower range which increased their rates somewhat offset by the decrease in higher dayrates associated with the terminated contracts.

Direct profit (contract drilling revenue less contract drilling operating expense) for the third quarter of 2012 decreased 16% from the second quarter of 2012 and increased 8% over the third quarter of 2011. During the third quarter 2012, we received $6.7 million in termination fees compared to $15.1 million in termination fees during the second quarter of 2012. Each comparative period had three drilling rigs that were under long-term contracts but were terminated early by the operator. Direct profit in the third quarter of 2012 compared to the third quarter of 2011 also benefited from increased dayrates, but to a lesser extent.

Operating cost per day for the third quarter of 2012 increased 1% over the second quarter of 2012 and increased 8% over the third quarter of 2011. The increases were primarily due to higher indirect costs 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 98% of our working drilling rigs are drilling for oil or NGLs. Of those, approximately 95% are drilling horizontal or directional wells.

As of September 30, 2012, we had 32 term drilling contracts with original terms ranging from six months to three years. Eleven of these contracts are up for renewal in the fourth quarter of 2012 and 21 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 first nine months of 2012, we had seven 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 $22.5 million and are included in revenue for nine months ended September 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).

During the third quarter of 2012, we had a fire on one of our rigs in the mid-continent region. The net book value of the damaged equipment on the rig was $3.2 million and we expect that all costs will be recoverable from insurance proceeds. As a result of this loss, this segment has 127 drilling rigs in its fleet.

Our 2012 estimated capital expenditures for this segment are $73.0 million.

Oil and Natural Gas

Third quarter 2012 production from our oil and natural gas segment was 3,499,000 barrels of oil equivalent (Boe), a 5% increase over the second quarter of 2012 and a 12% increase over the third quarter of 2011. These increases came primarily from new wells completed in oil and NGL rich prospects that were brought online and, to a lesser extent, from production associated with acquisitions. Third quarter 2012 oil and NGL production was 44% of our total production compared to 38% of our total production over the third quarter of 2011.

Third quarter 2012 oil and natural gas revenues decreased 1% from the second quarter of 2012 and decreased 3% from the third quarter of 2011. The decreases from the second quarter of 2012 were primarily due to decreases in oil and NGL prices. The decreases from the third quarter of 2011 were primarily due to decreased NGL and natural gas prices somewhat offset by increased production.

Our oil prices for the third quarter of 2012 decreased 2% from the second quarter of 2012 and increased 6% over the third quarter of 2011, respectively. Our NGL and natural gas prices decreased 34% and increased 12%, respectively, from the second quarter of 2012 and decreased 53% and 23%, respectively, from the third 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 million, net of tax). At September 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, were at levels that did not require us to take a write-down of our oil and natural gas properties. If there are further declines in the 12-month average prices, including the discounted value of our cash flow hedges, we may be required to record a write-down in future periods.

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Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 4% from the second quarter of 2012 and decreased 10% from the third quarter of 2011. The decreases over the respective periods were primarily attributable to decreases in prices along with increased lease operating expenses. Direct profit in the third quarter of 2011 was higher due to a $4.5 million decrease in gross production taxes from refunds attributable to high cost gas wells.

Operating cost per Boe produced for the third quarter of 2012 increased 4% over the second quarter of 2012 and increased 9% over the third quarter of 2011. Costs were higher between the respective periods due to higher lease operating expenses and gross production taxes.

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 5,500 Bbls per day of oil production and 100,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $99.71 per barrel. The natural gas production is hedged by swaps for 80,000 Mmbtu per day and a collar for 20,000 Mmbtu per day. The swap transactions were done at a comparable average NYMEX price of $3.65. The collar transaction was done at a comparable average NYMEX floor price of $3.25 and ceiling price of $3.72.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble Energy, Inc. (Noble). The acquisition includes approximately 84,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The amount paid at closing was $594.5 million. As of the effective date of April 1, 2012, the estimated proved reserves of the acquired properties were 44 million barrels of oil equivalent (MMBoe), The acquisition adds approximately 25,000 net acres to our Granite Wash core area in the Texas Panhandle with significant resource potential including approximately 600 potential horizontal drilling locations. The total acreage acquired in western Oklahoma is approximately 59,000 net acres and is characterized by high working interest and operatorship, 95% of which is held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

Also in September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison counties of Texas, including Buda and Woodbine production and associated acreage for approximately $44.1 million.

For 2012, we plan to participate in the drilling of 160 to 170 wells and our estimated capital expenditures are $492.0 million (excluding acquisitions). As of September 30, 2012, we completed drilling 129 wells (58.02 net wells). Unit's annual production guidance for 2012, including the impact of the Noble acquisition, is approximately 13.9 to 14.2 MMBoe, an increase of 15% to 17% over 2011.

Mid-Stream

Third quarter 2012 liquids sold per day decreased 8% from the second quarter of 2012 and increased 28% over the third quarter of 2011. During the third quarter 2012, one of our customers completed construction of their own processing plant and moved their volumes off our system resulting in decreases from the second quarter of 2012 in liquids sold, gas gathered and gas processed. The increases over the third quarter of 2011 were primarily the result of upgrades and expansions to existing plants and the connection of new wells. For the third quarter of 2012, gas processed per day decreased 6% from the second quarter of 2012 and increased 28% over the third quarter of 2011. In 2011 and 2012, we upgraded several of our existing processing facilities and added several processing plants which was the primary reason for increased volumes over last year. For the third quarter of 2012, gas gathered per day decreased 8% from the second quarter of 2012 and increased 22% over the third quarter of 2011. The increases were primarily from new well connects.

NGL prices in the third quarter of 2012 increased 5% over the price received in the second quarter of 2012 and decreased 39% from the price received in the third 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 third quarter of 2012 decreased 10% both

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from the second quarter of 2012 and the third quarter of 2011. The decreases were primarily due to decreases in NGL prices between the third quarter of 2012 and the third quarter of 2011 and reduced liquids volumes between the third quarter of 2012 and the second quarter of 2012. Total operating cost for our mid-stream segment for the third quarter of 2012 increased 9% over the second quarter of 2012 due to increases in price for gas purchased and increased field direct cost from the expansion of plants and decreased 13% from the third quarter of 2011 due primarily to decreases in price for gas purchased offset by the increase in field direct cost from the expansion of plants.

During the second quarter of 2012, we 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 45 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 first quarter of 2013. We are also connecting 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 in the process of extending the system approximately 20 miles to connect to third-party producers. We anticipate this extension will be completed in the fourth quarter of 2012. In addition to these construction projects, we are in the process of laying a liquids line from our Bellmon facility to Medford, Oklahoma. This project consists of approximately 24 miles of 6” pipe and is scheduled to be completed by the end 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 15 MMcf per day from six wells connected to this system. Construction of the first phase has been completed and we anticipate connecting five new wells in the fourth quarter of this year. Construction activity for expansion of this pipeline continues as the producer is maintaining its drilling activity.

Our 2012 estimated capital expenditures are $168.0 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 NGL production; and
- the margins we obtain from our natural gas gathering and processing contracts.

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

	September 30, 2012	2011	% Change
	(In thousands except percentages)		
Working capital	$(37,363)	$57,914	(165)%
Long-term debt	$645,154	$305,400	111%
Shareholders' equity	$2,028,976	$1,910,435	6%
Ratio of long-term debt to total capitalization	24%	14%	71%
Net income	$79,723	$144,206	(45)%
Net cash provided by operating activities	$512,140	$417,851	23%
Net cash used in investing activities	$(888,597)	$(583,790)	52%
Net cash provided by financing activities	$376,645	$165,740	127%

The following table summarizes certain operating information:

	Nine Months Ended September 30, 2012	2011	% Change
Contract Drilling:			
Average number of our drilling rigs in use during the period	77	74	4%
Total number of drilling rigs owned at the end of the period	127	126	1%
Average dayrate	$19,982	$18,663	7%
Oil and Natural Gas:			
Oil production (MBbls)	2,367	1,767	34%
Natural gas liquids production (MBbls)	2,014	1,623	24%
Natural gas production (MMcf)	34,403	32,730	5%
Average oil price per barrel received	$92.96	$86.80	7%
Average oil price per barrel received excluding hedges	$91.93	$93.75	(2)%
Average NGL price per barrel received	$30.70	$43.72	(30)%
Average NGL price per barrel received excluding hedges	$29.61	$44.65	(34)%
Average natural gas price per mcf received	$3.26	$4.33	(25)%
Average natural gas price per mcf received excluding hedges	$2.29	$3.94	(42)%
Mid-Stream:			
Gas gathered—MMBtu/day	276,566	201,788	37%
Gas processed—MMBtu/day	166,296	102,493	62%
Gas liquids sold—gallons/day	576,358	378,585	52%
Number of natural gas gathering systems	40	34	18%
Number of processing plants	13	10	30%

At September 30, 2012, we had unrestricted cash totaling $1.0 million and had borrowed none of the $500.0 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.

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On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of senior subordinated notes (the 2012 Notes) due May 15, 2021, which will bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance the acquisition of oil and natural gas properties from Noble. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes.

On registration, the Exchanged Notes will be treated as a single series of debt securities with our previously issued and outstanding notes bringing the total to $650.0 million aggregate principal amount of 6.625% senior subordinated notes.

On September 5, 2012, we amended our existing credit agreement, increasing the commitment amount from $250 million ($600 million borrowing base) to $500 million ($800 million borrowing base). This was done in conjunction with the closing of our agreement with Noble to acquire certain oil and natural gas assets.

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 negative working capital of $37.4 million and positive working capital of $57.9 million as of September 30, 2012 and 2011, respectively. The effect of our hedging activity increased working capital by $8.3 million as of September 30, 2012 and increased working capital by $25.0 million as of September 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 nine months of 2012, our average dayrate was $19,982 per day compared to $18,663 per day for the first nine months of 2011. The average number of our drilling rigs used in the first nine months of 2012 was 77.2 drilling rigs compared with 74.0 drilling rigs in the first nine months of 2011. Based on the average utilization of our drilling rigs during the first nine months of 2012, a $100 per day change in dayrates has a $7,720 per day ($2.8 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 $37.7 million and $39.9 million for the nine months of 2012 and 2011, respectively, from our contract drilling segment and eliminated the associated operating expense of $24.8 million and $24.9 million during the nine months of 2012 and 2011, respectively, yielding $12.9 million and $15.0 million during the nine 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 nine 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 $365,000 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 nine months of 2012 was $3.26 compared to $4.33 for the first nine months of 2011. Based on our first nine months of 2012 production, a $1.00 per barrel change in our oil price, without the effect of hedging, would have a $249,000 per month ($3.0 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 $212,000 per month ($2.5 million annualized) change in our pre-tax operating cash flow. In the first nine months of 2012, our average oil price per barrel received, including the effect of hedging, was $92.96 compared with an average oil price, including the effect of hedging, of $86.80 in the first nine months of 2011 and our first nine months of 2012 average NGLs price per barrel received, including the effect of hedging, was $30.70 compared with an average NGL price per barrel of $43.72 in the first nine 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. In the second quarter of 2012, 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). At September 30, 2012, the 12-month average unescalated prices were $94.97 per barrel of oil, $48.85 per barrel of NGLs, and $2.83 per Mcf of natural gas, adjusted for price differentials. We were not required to take a write-down in the third quarter of 2012. If there are further declines in the 12-month average prices, including the discounted value of our cash flow 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, 13 processing plants, 40 gathering systems and 1,143 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 nine months of 2012 and 2011, our mid-stream operations purchased $47.5 million and $52.5 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 $3.0 million and $3.5 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 276,566 MMBtu per day in the first nine months of 2012 compared to 201,788 MMBtu per day in the first nine months of 2011. Processed volumes were 166,296 MMBtu per day in the first nine months of 2012 compared to 102,493 MMBtu per day in the first nine months of 2011. The amount of NGLs we sold was 576,358 gallons per day in the first nine months of 2012 compared to 378,585 gallons per day in the first nine months of 2011. Gas gathering volumes per day in the first nine months of 2012 increased 37% compared to the first nine months of 2011 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes increased 62% over the comparative nine months and NGLs sold also increased 52% 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

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of our Hemphill facility in the Texas Panhandle.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement.On September 5, 2012, we amended our Senior Credit Agreement (credit agreement) scheduled to mature on 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 (amended to $500.0 million from $250.0 million) or the value of the borrowing base as determined by the lenders (amended to $800.0 million from $600.0 million), but in either event not to exceed the maximum credit agreement amount of $900.0 million (amended from $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 amendment, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. At October 22, 2012, borrowings were $35.0 million, there were no borrowings at September 30, 2012.

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)	17.00	%
Compass	17.00	%
Bank of Montreal	15.00	%
Bank of America, N.A.	15.00	%
Comerica Bank	8.00	%
Crédit Agricole Corporate and Investment Bank, London Branch	8.00	%
Wells Fargo Bank, National Association	8.00	%
Canadian Imperial Bank of Commerce	8.00	%
The Bank of Nova Scotia	4.00	%
	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 September 30, 2012, we did not have any outstanding borrowings under our credit facility.

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.

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

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

As of September 30, 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 2011 Notes). The 2011 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 debt issuance cost over the life of the 2011 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 2011 Notes were registered under the Securities Act.

On July 24, 2012, we completed the sale of $400.0 million aggregate principal amount of senior subordinated notes (the 2012 Notes) due May 15, 2021, which will bear interest at a rate of 6.625% per year. The 2012 Notes were sold at 98.75% of par plus accrued interest from May 15, 2012. We used the net proceeds from the offering to partially finance the acquisition of oil and natural gas properties from Noble. We incurred $8.7 million of fees that are being amortized as debt issuance cost over the life of the 2012 Notes. The 2012 Notes were not registered under the Securities Act.

Under the registration rights agreement filed with the SEC on Form 8-K on July 25, 2012, we are going to offer to exchange the 2012 Notes for additional notes of our existing 2011 Notes, which are registered under the Securities Act and have terms substantially identical to those of the 2012 Notes. After the exchange is completed, the 2012 Notes that are tendered (the Exchanged Notes) will be treated as a single series of debt securities with the 2011 Notes bringing the total to $650.0 million aggregate principal amount of 6.625% senior subordinated notes if all the 2012 Notes are tendered. The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the notes will mature on May 15, 2021.

The 2011 Notes and the 2012 Notes are, and the Exchange Notes will be, 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 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 their respective Indentures described below. 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 2011 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 2011 Notes (as supplemented, the 2011 Indenture). The 2012 Notes were issued under an Indenture dated as of July 24, 2012 between us, the Guarantors and the Trustee, as supplemented by the First Supplemental Indenture dated as of July 24, 2012, establishing the terms and providing for the issuance of the 2012 Notes (as supplemented, the 2012 Indenture). The discussion of the 2011 Notes and the 2012 Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture and the 2012 Indenture, respectively.

On and after May 15, 2016, we may redeem all or, from time to time, a part of the 2011 Notes, 2012 Notes, or Exchanged Notes (collectively, 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 2011 Indenture and the 2012 Indenture contain customary events of default. The Indentures governing the Notes contain covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of September 30, 2012.

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Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. During the third quarter of 2011, we were awarded two 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 127 drilling rigs in our fleet.

Our 2012 estimated capital expenditures for this segment are $73.0 million. At September 30, 2012, we had commitments to purchase approximately $1.5 million for new drilling rig components over the next twelve months. We spent $62.9 million for capital expenditures during the first nine months of 2012 compared to $122.3 million in the first nine months of 2011.

Oil and Natural Gas Dispositions, 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 129 gross wells (58.02 net wells) in the first nine months of 2012 compared to 119 gross wells (62.20 net wells) in the first nine months of 2011. Total capital expenditures for the first nine months of 2012 by this segment, excluding a $45.2 million net increase ARO liability and $575.4 million for acquisitions, totaled $384.2 million. Currently we plan to participate in drilling approximately 160 to 170 gross wells in 2012 and our total estimated capital expenditures (excluding acquisitions) for this segment are approximately $492.0 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.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble. The acquisition includes approximately 84,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The amount paid at closing was $594.5 million.

Also in September 2012, we sold our interest in certain Bakken properties (representing approximately 35% of our total acreage in the Bakken play). The proceeds, net of related expenses were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison counties of Texas, including Buda and Woodbine production and associated acreage for approximately $44.1 million.

Mid-Stream Acquisitions and Capital Expenditures. During the second quarter of 2012, we 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 45 MMcf per day at our Cashion facility.

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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 first quarter of 2013. We are also connecting 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 in the process of extending the system approximately 20 miles to connect to third-party producers. We anticipate this extension will be completed in the fourth quarter of 2012. In addition to these construction projects, we are in the process of laying a liquids line from our Bellmon facility to Medford, Oklahoma. This project consists of approximately 24 miles of 6” pipe and is scheduled to be completed by the end 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 15 MMcf per day from six wells connected to this system. Construction of the first phase has been completed and we anticipate connecting five new wells in the fourth quarter of this year. Construction activity for expansion of this pipeline continues as the producer is maintaining its drilling activity.

During the first nine months of 2012, our mid-stream segment incurred $120.3 million in capital expenditures ($18.7 million on four gathering systems acquired in the Noble acquisition) as compared to $59.3 million in the first nine months of 2011. For 2012, our estimated capital expenditures (excluding acquisitions) are $168.0 million. At September 30, 2012, we had commitments to purchase $1.8 million for a processing plant within the next twelve months.

Contractual Commitments

At September 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)	$1,021,281	$43,063	$86,125	$86,125	$805,968
Operating leases (2)	14,794	9,695	4,643	456	—
Drill pipe, drilling components and equipment purchases (3)	3,275	3,275	—	—	—
Total contractual obligations	$1,039,350	$56,033	$90,768	$86,581	$805,968

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our September 30, 2012 interest rates of 6.625% for the Notes. There was no outstanding borrowing under the credit facility at September 30, 2012.

(2) We lease office space or yards in Elmwood, Elk City, Oklahoma City and Tulsa, Oklahoma; Houston, Texas; 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 and $1.8 million for a processing plant over the next twelve months.

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At September 30, 2012, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period				
	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan (1)	$2,720	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$7,484	$472	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$2,065	$851	$1,214	$—	$—
Asset retirement liability (3)	$144,849	$2,857	$28,263	$6,772	$106,957
Gas balancing liability (4)	$3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$17,267	$8,084	$3,082	$1,186	$4,915

(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 discounted 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 $56,000 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. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. Therefore, the change in fair value, on all commodity derivatives entered into after that determination, will be reflected in the income statement and not in accumulated other comprehensive income (OCI).

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

	Q4’12	2013
Daily oil production	67 %	59 %
Daily natural gas production	35 %	79 %
Natural gas liquids production	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 September 30, 2012, we determined that the risk of non-performance by our counterparties was not material. At September 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:

	September 30, 2012 (In millions)
Bank of Montreal	$4.7
Comerica Bank	4.0
Crédit Agricole Corporate and Investment Bank, London Branch	3.1
BNP Paribas	2.5
BBVA Compass Bank	1.3
Macquarie Bank	0.4
Bank of America, N.A.	(1.6)
Total assets (liabilities)	$14.4

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our consolidated balance sheets. At September 30, 2012, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $14.5 million and $1.9 million, respectively and current and non-current derivative liabilities of $0.9 million and $1.2 million, respectively. 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.

For derivative transactions entered into before October 2012, we recognize in accumulated OCI the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of September 30, 2012, we had a gain of $9.9 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at September 30, 2012, we expect to transfer to earnings a gain of approximately $8.3 million, net of tax, of the income included in accumulated OCI during the next 12 months in the related month of production. The

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commodity derivative instruments existing as of September 30, 2012 are expected to mature by December 2013. Certain derivatives do not qualify for designation as cash flow hedges. As of September 30, 2012, 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 income 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 September 30:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Increases (decreases) in:				
Revenue:				
Realized gains (losses) on derivatives	$14,243	$1,814	$38,088	$(1,343)
Unrealized losses on ineffectiveness of cash flow hedges	(4,015)	2,336	(4,621)	4,158
Unrealized losses on non-qualifying derivatives	—	128	—	(547)
Total increase in revenues due to derivatives	$10,228	$4,278	$33,467	$2,268

Stock and Incentive Compensation

During the first nine months of 2012, we granted awards covering 395,051 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 $16.7 million. Compensation expense will be recognized over the three year vesting periods, and during the first nine months of 2012, we recognized $4.6 million in compensation expense and capitalized $1.0 million for these awards. During the first nine months of 2012, we recognized compensation expense of $8.2 million for all of our restricted stock, stock options and SAR grants and capitalized $2.0 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 nine months of 2012 and 2011, the total we received for all of these fees was $0.7 million and $2.4 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 September 30, 2012 versus Quarter Ended September 30, 2011
Provided below is a comparison of selected operating and financial data:

	Quarter Ended September 30, 2012	2011	Percent Change
Total revenue	$317,760,000	$323,845,000	(2)%
Net income	$46,586,000	$53,360,000	(13)%
Contract Drilling:			
Revenue	$133,420,000	$128,927,000	3 %
Operating costs excluding depreciation	$72,988,000	$73,004,000	— %
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	73.4	78.9	(7)%
Average dayrate on daywork contracts	$19,989	$19,309	4 %
Depreciation	$20,094,000	$20,818,000	(3)%
Oil and Natural Gas:			
Revenue	$131,420,000	$134,897,000	(3)%
Operating costs excluding depreciation, depletion and amortization	$36,147,000	$29,598,000	22 %
Average oil price (Bbl)	$91.07	$86.19	6 %
Average NGL price (Bbl)	$21.34	$45.40	(53)%
Average natural gas price (Mcf)	$3.40	$4.39	(23)%
Oil production (Bbl)	861,000	620,000	39 %
NGL production (Bbl)	684,000	578,000	18 %
Natural gas production (Mcf)	11,716,000	11,553,000	1 %
Depreciation, depletion and amortization rate (Boe)	$12.54	$15.00	(16)%
Depreciation, depletion and amortization	$44,489,000	$47,195,000	(6)%
Mid-Stream:			
Revenue	$52,935,000	$60,688,000	(13)%
Operating costs excluding depreciation and amortization	$46,267,000	$53,299,000	(13)%
Depreciation and amortization	$5,884,000	$4,017,000	46 %
Gas gathered—MMBtu/day	277,806	228,247	22 %
Gas processed—MMBtu/day	166,652	129,820	28 %
Gas liquids sold—gallons/day	576,889	449,604	28 %
General and administrative expense	$8,434,000	$7,800,000	8 %
Interest expense, net	$7,087,000	$1,351,000	NM
Income tax expense (benefit)	$29,784,000	$33,403,000	(11)%
Average interest rate	6.0 %	6.1 %	(2)%
Average long-term debt outstanding	$666,375,000	$288,014,000	131 %

(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 $4.5 million or 3% in the third quarter of 2012 versus the third quarter of 2011. The increase was primarily due to $6.7 million in termination fees for three drilling rigs that were under long-term contracts but were terminated early by the operator and a 4% increase in the average dayrate in the third quarter of 2012 compared to the third quarter of 2011. These increases were somewhat offset by a 7% decrease in the average number of drilling rigs in use during the third quarter of 2012 as compared to the third quarter of 2011. Average drilling rig utilization decreased from 78.9 drilling

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rigs in the third quarter of 2011 to 73.4 drilling rigs in the third 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 low natural gas and NGL prices, we are seeing a decrease in drilling activity in 2012.

Drilling operating costs were essentially unchanged between the comparative third quarters of 2012 and 2011. 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 decreased $0.7 million or 3%.

Oil and Natural Gas

Oil and natural gas revenues decreased $3.5 million or 3% in the third quarter of 2012 as compared to the third quarter of 2011 primarily due to decreases in NGL and natural gas prices. NGL prices decreased 53% to $21.34 per barrel, and natural gas prices decreased 23% to $3.40 per Mcf. These decreases were somewhat offset by an increase in equivalent production of 12.0% and an increase in oil prices. Average oil prices between the comparative quarters increased 6% to $91.07 per barrel. In the third quarter of 2012, as compared to the third quarter of 2011, oil production increased 39%, NGL production increased 18% and natural gas production increased 1%. 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 acquisitions.

Oil and natural gas operating costs increased $6.5 million or 22% between the comparative third quarters of 2012 and 2011 due to higher lease operating expenses and higher gross production taxes after the third quarter of 2011 was lower due to a $4.5 million reduction for the recognition of high cost gas credits. Lease operating expenses per Boe remained around $6.57 for the comparative periods.

Depreciation, depletion and amortization (“DD&A”) decreased $2.7 million or 6% primarily due to a 16% decrease in our DD&A rate offset by a 12.0% increase in equivalent production. The decrease in our DD&A rate in the third quarter of 2012 compared to the third quarter of 2011 resulted primarily from a reduction to the full cost pool from proceeds associated with the divestitures completed during the third quarter of 2012 and the non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax) that occurred during the second quarter of 2012. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Mid-Stream

Our mid-stream revenues decreased $7.8 million or 13% for the third quarter of 2012 as compared to the third quarter of 2011 primarily due to decreases in prices. The average price for natural gas sold decreased 34% and the average price for NGLs sold decreased 39%. Gas processing volumes per day increased 28% between the comparative quarters and NGLs sold per day increased 28% 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 22% primarily from well connections.

Operating costs decreased $7.0 million or 13% in the third quarter of 2012 compared to the third quarter of 2011 primarily due to a 36% decrease in prices paid for natural gas purchased offset by a 31% increase in the per day gas volumes purchased. Depreciation and amortization increased $1.9 million, or 46%, primarily due to increased assets placed into service throughout 2011 and 2012.

Other

General and administrative expenses increased $0.6 million or 8% in the third quarter of 2012 compared to the third quarter of 2011 primarily due to increases in the number of employees and increased employee costs.

Interest expense, net of capitalized interest, increased $5.7 million between the comparative third 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 6.1% to 6.0% and our average debt outstanding was $378.4 million higher in the third quarter of 2012 as compared to the third quarter of 2011 due to the issuance of $400.0 million of senior subordinated notes during the

third quarter of 2012 to partially fund the Noble acquisition in the oil and natural gas segment.
Income tax expense decreased $3.6 million or 11% in the third quarter of 2012 compared to the third quarter of 2011 primarily due to decreased income. Our effective tax rate was 39.0% for the third quarter of 2012 and 38.5% for the third quarter of 2011. Current income tax was a $3.9 million tax benefit for the third quarter of 2011 and a $2.5 million expense in

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the third quarter of 2012. We paid $0.1 million of income taxes in the third quarter of 2012.
Nine Months Ended September 30, 2012 versus Nine Months Ended September 30, 2011
Provided below is a comparison of selected operating and financial data:

	Nine Months Ended September 30, 2012	2011	Percent Change
Total revenue	$980,080,000	$862,745,000	14 %
Net income	$79,723,000	$144,206,000	(45)%
Contract Drilling:			
Revenue	$421,198,000	$342,098,000	23 %
Operating costs excluding depreciation	$223,980,000	$190,086,000	18 %
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	77.2	74.0	4 %
Average dayrate on daywork contracts	$19,982	$18,663	7 %
Depreciation	$62,660,000	$57,333,000	9 %
Oil and Natural Gas:			
Revenue	$397,745,000	$376,393,000	6 %
Operating costs excluding depreciation, depletion and amortization	$105,035,000	$93,796,000	12 %
Average oil price (Bbl)	$92.96	$86.80	7 %
Average NGL price (Bbl)	$30.70	$43.72	(30)%
Average natural gas price (Mcf)	$3.26	$4.33	(25)%
Oil production (Bbl)	2,367,000	1,767,000	34 %
NGL production (Bbl)	2,014,000	1,623,000	24 %
Natural gas production (Mcf)	34,403,000	32,730,000	5 %
Depreciation, depletion and amortization rate (Boe)	$15.06	$14.82	2 %
Depreciation, depletion and amortization	$153,839,000	$132,013,000	17 %
Impairment of oil and natural gas properties	$115,874,000	$—	— %
Mid-Stream:			
Revenue	$159,977,000	$144,820,000	10 %
Operating costs excluding depreciation and amortization	$136,243,000	$119,143,000	14 %
Depreciation and amortization	$16,330,000	$11,627,000	40 %
Gas gathered—MMBtu/day	276,566	201,788	37 %
Gas processed—MMBtu/day	166,296	102,493	62 %
Gas liquids sold—gallons/day	576,358	378,585	52 %
General and administrative expense	$23,814,000	$22,188,000	7 %
Interest expense, net	$11,455,000	$2,078,000	NM
Income tax expense	$51,127,000	$90,275,000	(43)%
Average interest rate	5.9 %	5.6 %	5 %
Average long-term debt outstanding	$433,544,000	$231,559,000	87 %

(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 $79.1 million or 23% in the first nine months of 2012 versus the first nine months of 2011 primarily due to a 4% increase in the average number of drilling rigs in use during the first nine months of 2012 compared to the first nine months of 2011 and a 7% increase in the average dayrate in the first nine months of 2012 compared to the first nine months of 2011. Average drilling rig utilization increased from 74.0 drilling rigs in the first nine months of 2011 to 77.2

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drilling rigs in the first nine 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 and NGL prices, we are seeing a decrease in drilling activity in 2012. During the first nine months of 2012, we had seven drilling rigs that were under contracts that were terminated early by the operator. The early termination fees associated with these contracts are approximately $22.5 million.

Drilling operating costs increased $33.9 million or 18% between the comparative first nine 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 $5.3 million or 9% 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 $21.4 million or 6% in the first nine months of 2012 as compared to the first nine months of 2011 primarily due to an increase in equivalent production of 14% and an increase in oil prices somewhat offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative nine month periods increased 7% to $92.96 per barrel, NGL prices decreased 30% to $30.70 per barrel and natural gas prices decreased 25% to $3.26 per Mcf. In the first nine months of 2012, as compared to the first nine months of 2011, oil production increased 34%, NGL production increased 24% and natural gas production increased 5%. 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 acquisitions.

Oil and natural gas operating costs increased $11.2 million or 12% between the comparative first nine months of 2012 and 2011 due to increases in lease operating expenses primarily from increased workover, saltwater disposal fees and compression and dehydration expense. Lease operating expenses per Boe decreased 1% to $6.56.

DD&A increased $21.8 million or 17% primarily due to an 2% increase in our DD&A rate and a 14% increase in equivalent production. The increase in our DD&A rate in the first nine months of 2012 compared to the first nine months of 2011 resulted primarily from increases throughout 2011 and the first nine months of 2012 from increased net book value on new reserves added. These increases were somewhat offset by a reduction to the full cost pool from proceeds associated with the divestitures completed during the third quarter of 2012 and the non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax) that occurred during the second quarter of 2012. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Mid-Stream

Our mid-stream revenues increased by $15.2 million or 10% for the first nine months of 2012 as compared to the first nine months of 2011 primarily due to higher NGL volumes sold offset by lower prices. Gas processing volumes per day increased 62% between the comparative nine months and NGLs sold per day increased 52% between the comparative nine 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 37% between the comparative nine months primarily from well connections. The average price for natural gas sold decreased 41% and the average price for NGLs sold decreased 32% between the comparative nine month periods.

Operating costs increased $17.1 million or 14% in the first nine months of 2012 compared to the first nine months of 2011 primarily due to a 59% increase in the per day gas volumes purchased somewhat offset by a 35% decrease in prices paid for natural gas purchased. Depreciation and amortization increased $4.7 million, or 40%, primarily due to increased assets placed into service throughout 2011 and 2012.

Other

General and administrative expenses increased $1.6 million or 7% in the first nine months of 2012 compared to the first nine months of 2011 primarily due to increases in the number of employees and increased employee costs. Interest expense, net of capitalized interest, increased $9.4 million between the comparative first nine months of 2012 and 2011. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the

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construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate increased from 5.6% to 5.9% and our average debt outstanding was $202.0 million higher in the first nine months of 2012 as compared to the first nine months of 2011 due to the issuance of $250.0 million of senior subordinated notes during the second quarter of 2011, the issuance of $400.0 million of senior subordinated notes during the third quarter of 2012 and due to acquisitions in the oil and natural gas segment during the second half of 2011 and during the first nine months of 2012 along with construction of new rigs and mid-stream plants.

Income tax expense decreased $39.1 million or 43% primarily due to decreased income as a result of the non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax) that occurred during the second quarter of 2012. Our effective tax rate was 39.1% for the first nine months of 2012 and 38.5% for the first nine months of 2011. There was a $3.9 million current income tax benefit for the first nine months of 2011 and a $0.5 million expense in the first nine months of 2012. We paid $2.0 million of income taxes in the first nine 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,” similar expressions are used to identify forward-looking statements.

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

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

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

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the availability of and nature or lack of business opportunities that we pursue;
- demand for our land drilling services;

- changes in laws or regulations;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may

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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 NGL and natural gas production. Historically, the prices we received for our oil, NGL, 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 the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first nine months 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 $365,000 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 $249,000 per month ($3.0 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 $212,000 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 September 30, 2012, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Oct’12 – Dec’12	Crude oil – swap	6,250 Bbl/day	$97.72	WTI – NYMEX
Jan’13 – Dec’13	Crude oil – swap	5,500 Bbl/day	$99.71	WTI – NYMEX
Oct’12 – Dec’12	Natural gas – swap	30,000 MMBtu/day	$5.05	IF – NYMEX (HH)
Oct’12 – Dec’12	Natural gas – swap	15,000 MMBtu/day	$5.62	IF – PEPL
Jan’13 – Dec’13	Natural gas – swap	60,000 MMBtu/day	$3.56	IF – NYMEX (HH)
Jan’13 – Dec’13	Natural gas – collar	20,000 MMBtu/day	$3.25-3.72	IF – NYMEX (HH)
Oct’12 – Dec’12	Liquids – swap (1)	180,006 Gal/mo	$2.11	OPIS – Conway
Oct’12 – Dec’12	Liquids – swap (2)	310,000 Gal/mo	$0.67	OPIS – Mont Belvieu

(1)Types of liquids involved are natural gasoline.

(2)Types of liquids involved are ethane.

After September 30, 2012, we entered into the following non-designated hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan’13 – Dec’13	Natural gas – swap	20,000 MMBtu/day	$3.94	IF – NYMEX (HH)

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

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Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of September 30, 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 September 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

Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson and Charlotte Abernathy are the Plaintiffs in this case and are royalty owners in oil and gas drilling and spacing units for which the company's exploration segment distributes royalty. The Plaintiffs' central allegation is that the company's exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We have asserted several defenses including that the deductions are permitted under Oklahoma law. We have also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012 the court of civil appeals reversed the trial court's order certifying the class. The Plaintiff's petitioned the supreme court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. It is not currently known whether the Plaintiffs will continue to seek adjudication of the merits of their claims absent a certified class of plaintiffs.

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

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operations. In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions, 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 September 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
July 1, 2012 to July 31, 2012	275	$39.01	275	—
August 1, 2012 to August 31, 2012	20,650	42.27	20,650	—
September 1, 2012 to September 30, 2012	—	—	—	—
Total	20,925	$42.23	20,925	—

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

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: November 1, 2012	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: November 1, 2012	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer