UNIT CORP
Form 10-Q
November 01, 2007

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, 2007

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer.

Large accelerated filer [x]   Accelerated filer [ ]   Non-accelerated filer [ ]

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 29, 2007, 46,381,533 shares of the issuer's common stock were outstanding.

FORM 10-Q
UNIT CORPORATION

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Forward-Looking Statements

This document contains “forward-looking statements” – that is, statements related to future, not past, events. In this context, forward-looking statements often address our expected future business and financial performance, and often contain words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “seek,” or “will.” Forward-looking statements by the nature address matters that are, to different degrees, uncertain. For us, particular uncertainties that could adversely or positively affect our future results include: the behavior of financial markets, including fluctuations in interest and commodity and equity prices; strategic actions, including acquisitions and dispositions; future integration of acquired businesses; future financial performance of industries which we serve, including, without limitation, the energy industries; and numerous other matters of national, regional and global scale, including those of a political, economic, business and competitive nature. These uncertainties may cause our actual future results to be materially different than those expressed in our forward-looking statements. We do not undertake to update our forward-looking statements.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

		September 30, 2007		December 31, 2006
		(In thousands)		
ASSETS				
Current Assets:				
Cash and cash equivalents	$	853	$	589
Restricted cash		19		18
Accounts receivable, net of allowance for doubtful accounts of $3,350 at September 30, 2007 and $1,600 at December 31, 2006		165,392		200,415
Materials and supplies		16,932		18,901
Other		16,388		13,017
Total current assets		199,584		232,940
Property and Equipment:				
Drilling equipment		948,125		781,190
Oil and natural gas properties, on the full cost method:				
Proved properties		1,528,655		1,330,010
Undeveloped leasehold not being amortized		66,327		53,687
Gas gathering and processing equipment		110,530		85,339
Transportation equipment		22,400		20,749
Other		19,618		17,082
		2,695,655		2,288,057
Less accumulated depreciation, depletion, amortization and impairment		874,069		735,394
Net property and equipment		1,821,586		1,552,663
Goodwill		62,808		57,524
Other Intangible Assets, Net		14,960		17,087
Other Assets		14,523		13,882
Total Assets	$	2,113,461	$	1,874,096

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

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

	September 30, 2007	December 31, 2006
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 94,439	$ 92,125
Accrued liabilities	43,280	52,166
Income taxes payable	—	2,956
Contract advances	3,231	5,061
Current portion of other liabilities	10,475	8,634
Total current liabilities	151,425	160,942
Long-Term Debt	153,600	174,300
Other Long-Term Liabilities	52,135	55,741
Deferred Income Taxes	397,690	325,077
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, 46,379,233 and 46,283,990 shares issued, respectively	9,280	9,257
Capital in excess of par value	341,744	333,833
Accumulated other comprehensive income (loss)	(129)	1,339
Retained earnings	1,007,716	813,607
Total shareholders' equity	1,358,611	1,158,036
Total Liabilities and Shareholders' Equity	$ 2,113,461	$ 1,874,096

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

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 157,769	$ 182,461	$ 472,403	$ 519,799
Oil and natural gas	95,231	91,238	277,680	267,518
Gas gathering and processing	32,784	25,638	99,321	72,840
Other	551	557	842	2,894
Total revenues	286,335	299,894	850,246	863,051
Expenses:				
Contract drilling:				
Operating costs	77,951	78,595	228,967	238,021
Depreciation	14,793	13,403	41,192	38,089
Oil and natural gas:				
Operating costs	23,101	21,560	69,701	58,854
Depreciation, depletion and amortization	32,297	27,557	92,367	76,780
Gas gathering and processing:				
Operating costs	28,275	22,216	87,171	63,734
Depreciation and amortization	2,858	1,637	7,752	4,019
General and administrative	5,355	4,630	15,784	12,998
Interest	1,797	1,228	5,167	3,235
Total expenses	186,427	170,826	548,101	495,730
Income Before Income Taxes	99,908	129,068	302,145	367,321
Income Tax Expense:				
Current	11,152	26,442	53,498	89,741
Deferred	24,695	21,361	54,538	46,585
Total income taxes	35,847	47,803	108,036	136,326
Net Income	$ 64,061	$ 81,265	$ 194,109	$ 230,995
Net Income per Common Share:				
Basic	$ 1.38	$ 1.76	$ 4.19	$ 5.00
Diluted	$ 1.37	$ 1.75	$ 4.16	$ 4.98

The accompanying notes are an integral part of the
Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2007	2006
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 194,109	$ 230,995
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	141,968	119,422
Deferred tax expense	54,538	46,585
Other	3,792	5,843
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	35,023	(4,840)
Accounts payable	(24,497)	(27,424)
Material and supplies inventory	1,969	(9,044)
Accrued liabilities	(14,066)	(9,139)
Contract advances	(1,830)	5,129
Other – net	(1,627)	(7,928)
Net cash provided by operating activities	389,379	349,599
Cash Flows From (Used In) Investing Activities:		
Capital expenditures	(344,524)	(299,312)
Cash paid for acquisitions	(38,500)	(53,820)
Proceeds from disposition of assets	3,866	5,865
Other-net	(388)	(241)
Net cash used in investing activities	(379,546)	(347,508)
Cash Flows From (Used In) Financing Activities:		
Borrowings under line of credit	144,600	183,200
Payments under line of credit	(165,300)	(183,100)
Proceeds from exercise of stock options	659	726
Tax benefit from stock options	—	290
Book overdrafts	10,472	(3,548)
Net cash used in financing activities	(9,569)	(2,432)
Net Increase (Decrease) in Cash and Cash Equivalents	264	(341)
Cash and Cash Equivalents, Beginning of Period	589	947
Cash and Cash Equivalents, End of Period	$ 853	$ 606

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Net Income	$ 64,061	$ 81,265	$ 194,109	$ 230,995
Other Comprehensive Income, Net of Taxes:				
Change in value of derivative instruments used as cash flow hedges (net of tax of $(52), $(62), $(566) and $161)	(122)	(106)	(1,026)	273
Reclassification - derivative settlements (net of tax of $(93), $(87), $(269) and $(158))	(121)	(148)	(442)	(267)
Comprehensive Income	$ 63,818	$ 81,011	$ 192,641	$ 231,001

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this quarterly report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms "company", "Unit," "we," "our" and "us" refer to Unit Corporation, a Delaware corporation, and its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires.

The accompanying interim condensed consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Form 10-K, filed March 1, 2007, for the year ended December 31, 2006. The accompanying condensed consolidated financial statements include all normal recurring adjustments that we consider necessary to state fairly our financial position at September 30, 2007, results of operations for the three and nine months ended September 30, 2007 and 2006 and cash flows for the nine months ended September 30, 2007 and 2006. All intercompany transactions have been eliminated.

Our financial statements are prepared in conformity with generally accepted accounting principles (GAAP) in the U.S. Preparing financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the amounts reported in our condensed consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Results for the three and nine months ended September 30, 2007 and 2006 are not necessarily indicative of the results to be realized during the full year. With respect to the unaudited financial information of the company for the three and nine month periods ended September 30, 2007 and 2006, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards for a review of that information. Its separate report dated November 1, 2007 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 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 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.

Before January 1, 2006, we accounted for our stock-based compensation plans under the recognition and measurement principles of Accounting Principles Board No. 25 (APB 25), “Accounting for Stock Issued to Employees,” and related Interpretations. Under APB 25, no stock-based employee compensation costs relating to stock options were reflected in net income since all options granted under the company’s plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment, (FAS 123(R)) to account for stock-based employee compensation. FAS 123(R) eliminated the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize in their financial statements the cost of employee services received in exchange for equity awards based on the grant date fair value of those awards. We elected to use the modified prospective method in applying FAS123(R), which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Financial statements for prior periods have not been restated. On adoption of FAS 123(R), we elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Staff Position No. FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards", issued on November 10, 2005. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, is being recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and operating costs of the company’s business segments. We use the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights. The value of restricted stock grants is based on the closing stock price on the date of the grant.

In the third quarter and first nine months of 2007, we recognized stock compensation expense for restricted stock awards, stock appreciation rights and stock options of $1.7 million and $3.3 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.3 million and $0.6 million, respectively. The tax benefit related to this stock based compensation was $0.6 million and $1.1 million for the third quarter and first nine months of 2007, respectively. The remaining unrecognized compensation cost related to unvested awards at September 30, 2007 is approximately $19.2 million with $5.0 million of this amount to be capitalized. The weighted average period of time over which this cost will be recognized is 1.4 years.

In the third quarter and first nine months of 2006, we recognized stock compensation expense for restricted stock awards and stock options of $0.9 million and $2.2 million, respectively and capitalized stock compensation cost for oil and natural gas properties of $0.2 million and $0.6 million, respectively. The tax benefit related to this stock based compensation was $0.3 million and $0.8 million, respectively for the third quarter and first nine months of 2006.

No stock appreciation rights were granted during the third quarters or first nine months of 2007 and 2006.

No stock options were granted during the three month periods ending September 30, 2007 and 2006. The following table estimates the fair value of each stock option granted during the nine months ended September 30, 2007 and 2006 using the Black-Scholes model applying the estimated values presented in the table:

	Nine Months Ended September 30,	
	2007	**2006**
Options Granted	28,000	33,000
Estimated Fair Value (In Millions)	$ 0.6	$ 0.8
Estimate of Stock Volatility	0.33	0.38
Estimated Dividend Yield	—%	—%
Risk Free Interest Rate	5.00%	5.00%
Expected Life Based on Prior Experience (In Years)	5	3 to 7

Expected volatilities are based on the historical volatility of our common stock. We use historical data to estimate stock option exercise and employee termination rates within the model and aggregates groups of employees 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 United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised. Stock options granted in the first nine months of 2007 increased stock compensation expense for the third quarter and first nine months of 2007 by $0.3 million and $0.5 million, respectively.

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The following table shows the fair value of restricted stock awards granted during the three and nine month periods ended September 30, 2007 and 2006:

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Shares Granted	409,932	—	415,432	—
Estimated Fair Value (In Millions)	$ 17.6	$ —	$ 17.9	$ —
Percentage of Shares Granted Expected to be Distributed	89%	—	89%	—

The restricted stock awards granted in the first nine months of 2007 increased stock compensation expense for the third quarter and first nine months of 2007 by $0.7 million.

NOTE 2 - EARNINGS PER SHARE

Basic and diluted earnings per share for the three month periods indicated were computed as follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Three Months Ended September 30, 2007:			
Basic earnings per common share	$ 64,061	46,382	$ 1.38
Effect of dilutive stock options and restricted stock shares	—	249	(0.01)
Diluted earnings per common share	$ 64,061	46,631	$ 1.37
For the Three Months Ended September 30, 2006:			
Basic earnings per common share	$ 81,265	46,241	$ 1.76
Effect of dilutive stock options and restricted stock shares	—	203	(0.01)
Diluted earnings per common share	$ 81,265	46,444	$ 1.75

The following stock options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended September 30, 2007 and 2006 because the option exercise prices were greater than the average market price of our common stock:

	2007	2006

Options	61,000	33,000
Average Exercise Price	$ 59.67	$ 61.40

Basic and diluted earnings per share for the nine month periods indicated were computed as follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Nine Months Ended September 30, 2007:			
Basic earnings per common share	$ 194,109	46,361	$ 4.19
Effect of dilutive stock options and restricted stock shares	—	259	(0.03)
Diluted earnings per common share	$ 194,109	46,620	$ 4.16
For the Nine Months Ended September 30, 2006:			
Basic earnings per common share	$ 230,995	46,223	$ 5.00
Effect of dilutive stock options and restricted stock shares	—	206	(0.02)
Diluted earnings per common share	$ 230,995	46,429	$ 4.98

The following stock options and their average exercise prices were not included in the computation of diluted earnings per share for the nine months ended September 30, 2007 and 2006 because the option exercise prices were greater than the average market price of our common stock:

	2007	2006
Options	61,000	29,500
Average Exercise Price	$ 59.67	$ 62.29

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NOTE 3 – ACQUISITION

On June 5, 2007, our subsidiary, Unit Drilling Company, closed the purchase of a privately owned drilling company operating primarily in the Texas Panhandle. The acquisition included nine drilling rigs, drill pipe and collars, a fleet of 11 trucks, an office, shop, equipment yard and personnel. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Eight of the drilling rigs acquired are operational and the remaining drilling rig is being refurbished and should be operational during the fourth quarter of 2007. Results of operations for the acquired company are included in our statement of income (beginning June 5, 2007). The total purchase price paid in this acquisition was allocated as follows (in thousands):

Drilling Rigs	$ 39,326
Spare Drilling Equipment	1,613
Drill Pipe and Collars	7,784
Trucks	1,551
Other Vehicles	190
Yard and Office	846
Goodwill	5,285
Deferred Income Taxes	(18,095)
Total Consideration	$ 38,500

NOTE 4 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

As of September 30, 2007 and December 31, 2006, long-term debt consisted of the following:

	September 30, 2007	December 31, 2006
	(In thousands)	
Revolving Credit Facility, with Interest at September 30, 2007 and December 31, 2006 of 6.4%	$ 153,600	$ 174,300
Less Current Portion	—	—
Total Long-Term Debt	$ 153,600	$ 174,300

On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of $400.0 million maturing on May 24, 2012. Borrowings under the Credit Facility are limited to a commitment amount elected by us. As of September 30, 2007, the commitment amount was $275.0

million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for the third quarter and first nine months of 2007 was 6.1%. At September 30, 2007 and October 29, 2007, borrowings were $153.6 million and $158.6 million, respectively.

The borrowing base under the Credit Facility is subject to redetermination on April 1 and October 1 of each year. The current borrowing base as determined by the lenders is $425.0 million. Each redetermination is based primarily on a percentage of the discounted future value of the company’s oil and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The company or the lenders may request a one time special redetermination of the borrowing base by each scheduled redetermination date. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility. The lender's aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million.

At Unit's election, any part of the outstanding debt may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day term. During any LIBOR funding period the outstanding principal balance of the note to which LIBOR options apply may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At September 30, 2007, all of the $153.6 million of the company's borrowings was subject to LIBOR.

The Credit Facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of the company's 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 the company's property, except in favor of the company's lenders.

The Credit Facility also requires that we have at the end of each quarter:

- consolidated net worth of at least $900 million;
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1; and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

On September 30, 2007, we were in compliance with the Credit Facility's covenants.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	September 30, 2007	December 31, 2006
	(In thousands)	
Plugging Liability	$ 30,762	$ 33,692
Workers' Compensation	22,646	22,157
Separation Benefit Plans	4,248	3,516
Deferred Compensation Plan	2,969	2,544

Gas Balancing Liability	1,080	1,080
Retirement Agreement	905	1,386
	62,610	64,375
Less Current Portion	10,475	8,634
Total Other Long-Term Liabilities	$ 52,135	$ 55,741

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Estimated annual principle payments under the terms of long-term debt and other long-term liabilities for the twelve month periods beginning October 1, 2007 through 2012 are $10.5 million, $4.5 million, $2.0 million, $2.0 million and $155.7 million, respectively. Based on the borrowing rates currently available to the company for debt with similar terms and maturities, long-term debt at September 30, 2007 approximates its fair value.

NOTE 5 – ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) we are required to record the fair value of liabilities associated with the retirement of long-lived assets. We own oil and natural gas properties which require cash to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted or the wells are no longer able to produce. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling these plugging liabilities.

The following table shows the activity for the nine months ended September 30, 2007 and 2006 relating to our retirement obligation for plugging liability:

	Nine Months Ended	
	2007	2006
	(In Thousands)	
Plugging Liability, January 1:	$ 33,692	$ 22,015
Accretion of Discount	1,326	1,091
Liability Incurred	1,274	2,835
Liability Settled	(1,382)	(156)
Revision of Estimates	(4,148)	6,061
Plugging Liability, September 30	30,762	31,846
Less Current Portion	1,678	643
Total Long-Term Plugging Liability	$ 29,084	$ 31,203

NOTE 6 - NEW ACCOUNTING PRONOUNCEMENTS

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS No. 109, "Accounting for Income Taxes" and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted the provisions of FIN 48 effective January 1, 2007. We have no unrecognized tax benefits and the adoption of FIN 48 had no effect on our results of operations or financial condition and we do not expect any significant changes in unrecognized tax benefits in the next twelve months. In the third quarter of 2007, the Internal Revenue Service completed their review of our 2004 federal tax return and no adjustments to the return were assessed.

In September 2006, the FASB issued Statement No. 157 (FAS 157), "Fair Value Measurements". FAS 157 establishes a common definition for fair value to be applied to GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about fair value measurements. FAS 157 is effective for fiscal years beginning after November 15, 2007. We are assessing the impact of FAS 157 on our statement of income, financial condition and cash flows.

In February 2007, the FASB issued Statement No. 159 (FAS 159), "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115", which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. We are assessing the impact of FAS 159 on our statement of income, financial condition and cash flows.

NOTE 7 – GOODWILL

Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. We incurred goodwill of $5.3 million as a result of the acquisition which closed on June 5, 2007. An annual impairment test is performed in the fourth quarter to determine whether the fair value has decreased and additionally when events indicate an impairment may have occurred. Goodwill is all related to our drilling segment.

NOTE 8 – HEDGING ACTIVITY

We periodically enter into derivative commodity instruments to hedge our exposure to the fluctuations in the prices we receive for our oil and natural gas production and mid-stream activities. These instruments include regulated natural gas and crude oil futures contracts traded on the NYMEX and over-the-counter swaps and basic hedges with major energy derivative product specialists.

In June 2007, we entered into natural gas liquids sales swaps and natural gas purchase swaps to lock in a percentage of our mid-stream segment's fractionation spread for natural gas processed. The fractionation spread is the difference in the value received for liquids recovered from natural gas in comparison to the amount received for the equivalent Million British thermal units (MMBtu's) of natural gas if unprocessed. These swaps pertain to approximately 65% of our mid-stream segments total liquid sales. The following table provides additional information pertaining to the swap contracts for the time periods covering July through November of 2007:

Commodity	Quantity	Price	Underlying Commodity Price
Ethane	623,868 gal./month	$ 0.6225	OPIS Ethane Conway
Propane	396,690 gal./month	$ 1.1475	OPIS Propane Conway
Propane	396,690 gal./month	$ 1.15	OPIS Propane Conway
Iso Butane	61,782 gal./month	$ 1.2625	OPIS Iso Butane Conway
Iso Butane	61,782 gal./month	$ 1.2975	OPIS Iso Butane Conway
Normal Butane	163,632 gal./month	$ 1.2975	OPIS Normal Butane Conway
Normal Butane	163,632 gal./month	$ 1.27	OPIS Normal Butane Conway
Natural Gasoline	411,012 gal./month	$ 1.7375	OPIS Nat. Gas Conway In-Well
Natural Gas	107,710 MMBtu/month	$ 7.00	IF PEPL Natural Gas
Natural Gas	107,710 MMBtu/month	$ 7.04	IF PEPL Natural Gas

All of these swaps are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the swap contracts was recognized on the September 30, 2007 balance sheet as a derivative liability of $1.6 million and a loss of $1.0 million, net of tax, in accumulated other comprehensive income for the nine months ended September 30, 2007.

In January and February 2007, we entered into the following two natural gas collar contracts:

First Contract:

Production volume covered	10,000 MMBtu/day
Period covered	March through December of 2007
Prices	Floor of \$6.00 and a ceiling of \$10.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East – Inside FERC

Second Contract:

Production volume covered	10,000 MMBtu/day
Period covered	March through December of 2007
Prices	Floor of \$6.25 and a ceiling of \$9.25
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East – Inside FERC

In December 2006, we also entered into the following natural gas hedging transaction:

Contract:

Production volume covered	10,000 MMBtu/day
Period covered	January through December of 2007
Prices	Floor of \$6.00 and a ceiling of \$9.60
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East – Inside FERC

All of these hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the September 30, 2007 balance sheet as a derivative asset of \$1.1 million and at a gain of \$0.7 million, net of tax, in accumulated other comprehensive income for the nine months ended September 30, 2007.

In February 2005, we entered into an interest rate swap to help manage exposure to possible future interest rate increases under our Credit Facility. The contract swaps \$50.0 million of variable rate debt to fixed rate debt and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, in the third quarter and first nine months of 2007, our interest expense was decreased by \$0.2 million and \$0.5 million, respectively. Our interest expense was decreased by \$0.2 million in the third quarter of 2006 and \$0.4 million for the nine months ended September 30, 2006. The fair value of the swap was recognized on the September 30, 2007 balance sheet as current and non-current derivative assets totaling \$0.3 million and a gain of \$0.2 million, net of tax, in accumulated other comprehensive income for the nine months ended September 30, 2007.

NOTE 9 - INDUSTRY SEGMENT INFORMATION

We have three main business segments:

. Contract Drilling,
. Oil and Natural Gas and

. Mid-Stream

These three segments represent our three main business units offering different products and services. The Contract Drilling segment is engaged in the land contract drilling of oil and natural gas wells, the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties and the Mid-Stream segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

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We evaluate the performance of these operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Our natural gas production in Canada is not significant. Information regarding our segment operations for the three and nine months ended September 30, 2007 and 2006 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Revenues:				
Contract drilling	$ 169,780	$ 196,953	$ 503,580	$ 550,428
Elimination of inter-segment revenue	12,011	14,492	31,177	30,629
Contract drilling net of inter-segment revenue	157,769	182,461	472,403	519,799
Oil and natural gas	95,231	91,238	277,680	267,518
Gas gathering and processing	40,042	29,045	112,908	83,303
Elimination of inter-segment revenue	7,258	3,407	13,587	10,463
Gas gathering and processing net of inter-segment revenue	32,784	25,638	99,321	72,840
Other (1)	551	557	842	2,894
Total revenues	$ 286,335	$ 299,894	$ 850,246	$ 863,051
Operating Income (2):				
Contract drilling	$ 65,025	$ 90,463	$ 202,244	$ 243,689
Oil and natural gas	39,833	42,121	115,612	131,884
Gas gathering and processing	1,651	1,785	4,398	5,087
Total operating income	106,509	134,369	322,254	380,660
General and administrative expense	(5,355)	(4,630)	(15,784)	(12,998)
Interest expense	(1,797)	(1,228)	(5,167)	(3,235)
Other income - net	551	557	842	2,894
Income before income taxes	$ 99,908	$ 129,068	$ 302,145	$ 367,321

(1) Includes a $1.0 million gain recognized in the first quarter of 2006 from insurance proceeds on the loss of a drilling rig from a blow out and fire in January 2006.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of September 30, 2007, and the related condensed consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2007 and 2006 and the condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2007 and 2006. 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, 2006, 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 March 1, 2007 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2006, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
November 1, 2007

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

- Financial Condition
- Results of Operations
- New Accounting Pronouncements

MD&A should be read in conjunction with the condensed consolidated financial statements and related notes included in this report as well as the information contained in our Annual Report on Form 10-K.

Unless otherwise indicated or required by the content, as used in this report, the terms company, Unit, us, our, we and its refer to Unit Corporation and, as appropriate, and/or one or more of its subsidiaries.

FINANCIAL CONDITION

Summary. Our financial condition and liquidity depends on the cash flow from our three principal business segments (and our subsidiaries that carry out those operations) and borrowings under our bank credit facility.

Our cash flow is influenced mainly by:

- the prices we receive for our natural gas production and, to a lesser extent, the prices we receive for our oil production;
- the quantity of natural gas and oil we produce;
- the demand for and the dayrates we receive for our drilling rigs; and
- the margins we obtain from our natural gas gathering and processing contracts.

Our three principal business segments are:

- contract drilling carried out by our subsidiaries Unit Drilling Company and its subsidiaries Unit Texas Drilling, L.L.C. and Leonard Hudson Drilling Company;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company; and its subsidiaries; and
- mid stream operations (consisting of natural gas buying, selling, gathering, processing and treating) carried out by our subsidiary Superior Pipeline Company, L.L.C.

The following is a summary of certain financial information as of September 30, 2007 and 2006 and for the nine months ended September 30, 2007 and 2006:

	September 30, 2007	September 30, 2006	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 48,159	$ 96,760	(50)%
Long-Term Debt	$ 153,600	$ 145,100	6%
Shareholders' Equity	$ 1,358,611	$ 1,074,561	26%
Ratio of Long-Term Debt to Total Capitalization	10%	12%	(17)%
Net Income	$ 194,109	$ 230,995	(16)%
Net Cash Provided by Operating Activities	$ 389,379	$ 349,599	11%
Net Cash Used in Investing Activities	$ (379,546)	$ (347,508)	9%
Net Cash Used in Financing Activities	$ (9,569)	$ (2,432)	293%

The following table summarizes certain operating information for the nine months ended September 30, 2007 and 2006:

	September 30, 2007	September 30, 2006	Percent Change
Oil Production (MBbls)	1,260	1,062	19%
Natural Gas Production (MMcf)	32,507	32,350	—%
Average Oil Price Received	$ 54.90	$ 57.18	(4)%
Average Oil Price Received Excluding Hedges	$ 54.90	$ 57.18	(4)%
Average Natural Gas Price Received	$ 6.30	$ 6.28	—%
Average Natural Gas Price Received Excluding Hedges	$ 6.24	$ 6.28	(1)%
Average Number of Our Drilling Rigs in Use During the Period	98.4	109.8	(10)%
Total Number of Drilling Rigs Available at the End of the Period	128	116	10%
Average Dayrate	$ 18,858	$ 18,442	2%
Gas Gathered—MMBtu/day	221,943	245,435	(10)%
Gas Processed—MMBtu/day	47,432	27,226	74%
Gas Liquids Sold—Gallons/day	115,781	57,840	100%
Number of Active Natural Gas Gathering Systems	36	37	(3)%
Number of Active Processing Systems	7	7	—%

At September 30, 2007, we had unrestricted cash totaling $0.9 million and we had borrowed $153.6 million of the $275.0 million we have elected to have available under our Credit Facility.

Our Bank Credit Facility. On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) which amended and restated the credit facility entered into between us and our lenders on January 30, 2004. The Credit Facility is a revolving credit facility maturing on May 24, 2012 and has a maximum credit amount of $400.0 million. Borrowings under the Credit Facility are limited to a commitment amount elected by us. On May 24, 2007, we elected to have an initial aggregate commitment amount of $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of our total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for the first nine months of 2007 was 6.1%. At September 30, 2007 and October 29, 2007, our borrowings were $153.6 million and $158.6 million, respectively.

The borrowing base under the Credit Facility is subject to re-determination on April 1 and October 1 of each year. The current borrowing base as determined by the lenders is $425.0 million. Each redetermination is based primarily on a percentage of the discounted future value of our oil and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The company or the lenders may request a one time special redetermination of the borrowing base by each scheduled redetermination date. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility. The lender's aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million.

At Unit's election, any part of the outstanding debt may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period the outstanding principal balance of the note to which such LIBOR option applies may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR Base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under the LIBOR bear interest at the BOKF National Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At September 30, 2007, all of the $153.6 million we had borrowed was subject to LIBOR.

The Credit Facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain limited exceptions, and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of our lenders.

The Credit Facility also requires that we have at the end of each quarter:

- consolidated net worth of at least $900 million,
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

On September 30, 2007, we were in compliance with the Credit Facility's covenants.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was decreased by $0.5 million in the first nine months of 2007. The fair value of the swap was recognized on the September 30, 2007 balance sheet as current derivative assets totaling $0.3 million and a gain of $0.2 million, net of tax, in accumulated other comprehensive income.

In October 2007, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $15.0 million of variable rate debt to fixed rate debt and covers the period from December 1, 2007 through May 31, 2012. The fixed rate is based on three-month LIBOR and is at 4.53%.

Contractual Commitments. At September 30, 2007 we had the following contractual obligations:

	Payments Due by Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Bank Debt (1)	$ 198,702	$ 9,395	$ 19,584	$ 169,723	$ —
Retirement Agreements (2)	905	727	178	—	—
Operating Leases (3)	3,904	1,504	2,091	309	—
Drill Pipe, Drilling Rigs and Equipment Purchases (4)	13,337	13,337	—	—	—
Total Contractual Obligations	$ 216,848	$ 24,963	$ 21,853	$ 170,032	$ —

(1) See the previous discussion in Management Discussion and Analysis regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated at the September 30, 2007 interest rate of 5.6% including the effect of the interest rate swap related to $50.0 million of the outstanding debt.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expense for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly installments of $25,000 which started in July 2003 and will continue through June 2009. In the first quarter of 2004, we acquired a liability for the present value of a separation agreement between PetroCorp Incorporated and one of its previous officers. The liability associated with this agreement is paid in quarterly installments of $12,500 through December 31, 2007. In the first quarter of 2005, we recorded $0.7 million in additional employee benefit expense for the present value of a separation agreement made in connection with the retirement of John Nikkel from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly installments of $31,250 which started in November 2006 and will continue through October 2008. These liabilities as presented above are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston and Midland, Texas; and Denver, Colorado under the terms of operating leases expiring through January 31, 2012. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(4) Due to the potential for limited availability of new drill pipe within the industry, we have committed to purchase approximately $9.3 million of drill pipe and drill collars. We have also committed to purchase $3.1 million of drilling rig components with 20% or $0.6 million paid through September 30, 2007. We have committed to purchase approximately 75 vehicles within the next 9 months for approximately $1.5 million.

At September 30, 2007, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Amount of Commitment Expiration Per Period			
Other Commitments	Total Amount Committed Or Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Deferred Compensation Agreement (1)	$ 2,969	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement (2)	$ 4,248	Unknown	Unknown	Unknown	Unknown
Plugging Liability (3)	$ 30,762	$ 1,678	$ 1,851	$ 2,638	$ 24,595
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$ 22,646	$ 8,070	$ 4,467	$ 1,480	$ 8,629

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

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. At September 30, 2007, there were 31 eligible employees to participate in the plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143), we have recorded the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for certain properties where we believe there are insufficient oil and natural gas reserves available 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 2007, with a subsidiary of ours serving as general partner. The Partnerships were formed for the purpose of conducting oil and natural gas

(5) - cont. acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $7,000, $4,000 and $14,000 in 2006, 2005 and 2004, respectively and have not had any repurchases in 2007.

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

***Hedging*.** Periodically we hedge the prices we will receive for a portion of our future natural gas and oil production and mid-stream activities. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow.

In June 2007, we entered into the following natural gas liquids sales swaps and natural gas purchase swaps to lock in a percentage of our mid-stream segment's fractionation spread for natural gas processed. The fractionation spread is the difference in the value received for liquids recovered from natural gas in comparison to the amount received for the equivalent MMBtu's of natural gas if unprocessed. These swaps pertain to approximately 65% of our mid-stream segments total liquid sales. The following table provides additional information pertaining to the swap contracts for the time periods covering July through November of 2007:

Commodity	Quantity	Price	Underlying Commodity Price
Ethane	623,868 gal./month	$ 0.6225	OPIS Ethane Conway
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All of these swaps are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the swap contracts was recognized on the September 30, 2007 balance sheet as a derivative liability of $1.6 million and a loss of $1.0 million, net of tax, in accumulated other comprehensive income for the nine months ended September 30, 2007.

In January and February 2007, we entered into the following two natural gas collar contracts:

First Contract:

Production volume covered	10,000 MMBtu/day
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Prices	Floor of $6.00 and a ceiling of $10.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East – Inside FERC

Second Contract:

Production volume covered	10,000 MMBtu/day
Period covered	March through December of 2007
Prices	Floor of $6.25 and a ceiling of $9.25
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East – Inside FERC

In December 2006, we entered into the following natural gas collar contract:

Contract:

Production volume covered	10,000 MMBtu/day
Period covered	January through December of 2007
Prices	Floor of $6.00 and a ceiling of $9.60
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East – Inside FERC

All of these hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the September 30, 2007 balance sheet as a derivative asset of $1.1 million and at a gain of $0.7 million, net of tax, in accumulated other comprehensive income for the nine months ended September 30, 2007.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed rate debt and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, in the third quarter and first nine months of 2007, our interest expense was decreased by $0.2 million and $0.5 million, respectively. Our interest expense was decreased by $0.2 million in the third quarter of 2006 and $0.4 million for the nine months ended September 30, 2006. The fair value of the swap was recognized on the September 30, 2007 balance sheet as current and non-current derivative assets totaling $0.3 million and a gain of $0.2 million, net of tax, in accumulated other comprehensive income for the nine months ended September 30, 2007.

In October 2007, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $15.0 million of variable rate debt to fixed rate debt and covers the period from December 1, 2007 through May 31, 2012. The fixed rate is based on three-month LIBOR and is at 4.53%.

Stock and Incentive Compensation. As an incentive to retain certain non-executive officer employees, during the third quarter of 2007, we granted 402,197 shares of restricted stock with a three year cliff vesting period under our Unit Corporation Stock and Incentive Compensation Plan. The restricted stock awards had an estimated fair value as of the grant date of $17.2 million. Compensation expense will be recognized over the three year vesting period, and during the third quarter of 2007 we recognized $0.7 million of compensation expense.

Self-Insurance or Retentions. We are self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.25 million for Oklahoma workers' compensation to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. If our insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. With respect to our drilling operations conducted by Unit Texas Drilling LLC in Texas, we have elected to use an ERISA governed occupational injury benefit plan to cover that company's field and support staff in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas**.** Natural gas comprises 85% of our total oil and natural gas reserves. Any significant change in natural gas prices has a material effect on our revenues, cash flow and the value of our oil and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our first nine months of 2007 production, a $0.10 per thousand cubic feet of natural gas (Mcf) change in what we are paid for our natural gas production would result in a corresponding $338,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. Our first nine months of 2007 average natural gas price was $6.30 compared to an average natural gas price of $6.28 for the first nine months of 2006. A $1.00 per barrel change in our oil price would have a 131,000 per month ($1.6 million annualized) change in our pre-tax

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operating cash flow based on our production in the first nine months of 2007. Our first nine month 2007 average oil price was $54.90 compared with an average oil price of $57.18 received in the first nine months of 2006.

Because oil and natural gas prices have such a significant affect on the value of our oil and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely effect the semi-annual determination of the amount available for us to borrow under our bank credit facility since that determination is based mainly on the value of our oil and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

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

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil 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 172 wells (60.24 net wells) in the first nine months of 2007 compared to 178 wells (62.27 net wells) in the first nine months of 2006. Our total capital expenditures for oil and natural gas exploration in the first nine months of 2007 totaled $213.1 million. We currently anticipate we will drill approximately 270 gross wells in 2007. We have estimated our total 2007 capital expenditures for oil and natural gas exploration to be approximately $326.0 million. Whether we are able to drill the number of wells we anticipate drilling in 2007 is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, the weather and the efforts of our outside industry partners.

On May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition were included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. Included in this acquisition were all of Brighton's oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and results of operations from this acquisition are included in the statement of income beginning October 1, 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

Contract Drilling. Our drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our rigs and our ability to supply the equipment needed.

Although rig utilization declined in the fourth quarter of 2006 and continued to slowly decline in the first nine months of 2007, we do not anticipate declines in labor cost per hour due to the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future technological requirements of the drilling industry. To help keep qualified labor, we previously implemented longevity pay incentives and in the second quarter of 2006 provided pay increases in some of our operating districts. To date, these efforts have allowed us to meet our labor requirements. However, if current demand for drilling rigs strengthens above the first nine month levels of 81%, shortages of experienced personnel may limit our ability to operate our drilling rigs.

We currently do not have any shortages of drill pipe and drilling equipment. Because of the potential for shortages in the availability of new drill pipe, at September 30, 2007 we have commitments to purchase approximately $9.3 million of drill pipe and drill collars in 2007 and we have also committed to purchase $3.1 million of additional rig components with 20% or $0.6 million paid through September 30, 2007.

One of the drilling rigs acquired in the second quarter of 2007 drilling acquisition is being refurbished and should begin drilling operations in the fourth quarter of 2007 and one additional rig is scheduled to be placed in service in the fourth quarter of 2007.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we can charge for our contract drilling services. In September 2007, our average dayrate for the 128 drilling rigs that we owned was $18,407 with a 77% utilization rate. In the first nine months of 2007 our average dayrate was $18,858 per day compared to $18,442 in the first nine months of 2006. The average number of drilling rigs used was 98.4 (81%) in the first nine months of 2007 compared to 109.8 (97%) in the first nine months of 2006. Based on the average utilization of our drilling rigs during the first nine months of 2007, a $100 per day change in dayrates has a $9,840 per day ($3.6 million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first nine months of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with high levels of natural gas storage throughout the majority of the winter season and again this summer. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas, the levels of natural gas storage and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties for comparable type projects. During the first nine months of 2007 and 2006, we drilled 52 and 50 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $15.7 million and $16.6 million during the first nine months of 2007 and 2006, respectively, reduced the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

Drilling Acquisitions and Capital Expenditures. In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This drilling rig has been modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May 2006, we began moving a 1,500 horsepower drilling rig to our Rocky Mountain Division following completion of its construction in the first quarter of 2006 for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two new 1,500 horsepower drilling rigs for a total of $15.2 million of which $4.6 million was paid before the second quarter of 2006 and the balance of $10.6 million was paid at delivery of the rigs. An additional $3.0 million of modifications were made to the rigs before the rigs were placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower rig for approximately $9.5 million which was moved into our Rocky Mountain Division. In the last half of 2006 we completed construction of a 750 horsepower rig for approximately $4.5 million.

During 2006 we purchased major components to construct two 1,500 horsepower drilling rigs. The first rig was moved to the Rocky Mountain division at the end of March 2007 and the second rig was placed in service in the second quarter of 2007 for a combined capitalized cost of $18.9 million. On June 5, 2007, we completed the acquisition of a privately owned drilling company operating primarily in the Texas Panhandle. The acquired drilling company owns nine drilling rigs, a fleet of 11 trucks, and an office, shop and equipment yard. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Seven of the nine drilling rigs were operating under contract at the acquisition date. Results of operations for the acquired company have been included in our statements of income beginning June 5, 2007. Total consideration paid for this acquisition was $38.5 million.

For our contract drilling operations, during the first nine months of 2007, we recorded $179.6 million in capital expenditures including the effect of an $18.1 million deferred tax liability and $5.3 million in goodwill associated with

our second quarter 2007 acquisition. For 2007, we anticipate capital expenditures to be approximately $166.0 million excluding acquisitions.
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Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. Superior is a mid-stream company engaged primarily in the buying and selling, gathering, processing and treating of natural gas and operates four natural gas treatment plants, seven operating processing plants, 36 active gathering systems and 651 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas and has been in business since 1996. This subsidiary enhances our ability to gather and market not only our own natural gas but also that owned by third parties and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During the first nine months of 2007, Superior purchased $10.0 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $3.6 million. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas exploration operations has been eliminated in our condensed consolidated financial statements. In the first nine months of 2006, we eliminated intercompany revenues of $6.4 million of natural gas production and natural gas liquids and $4.0 million of gathering and transportation services.

Mid-Stream Acquisitions and Capital Expenditures. In September 2006, we closed the acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition have been included in our statements of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

During the first nine months of 2007, Superior incurred $25.2 million in capital expenditures compared to $38.3 million for the same period in 2006. For 2007, we anticipate capital expenditures to be approximately $31.5 million for Superior. Our focus is on growing this segment through the construction of new facilities or acquisitions.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 12 oil and natural gas limited partnerships. Each partnership’s revenues and costs are shared under formulas prescribed in its limited partnership 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. The partnerships are charged their allocable share of general and administrative expense billed through well cost allocations. During 2006, the total paid to us for all of these fees was $1.3 million and during the first nine months of 2007 and 2006 the amount paid was $1.1 million and $0.9 million, respectively. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our condensed consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS No. 109, "Accounting for Income Taxes" and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted the provisions of FIN 48 effective January 1, 2007. We have no unrecognized tax benefits and the adoption of FIN 48 had no effect on our results of operations of financial condition and we do not expect any significant changes in unrecognized tax benefits in the next twelve months. In the third quarter of 2007, the Internal Revenue Service completed their review of our 2004 federal tax return and no adjustments to the return were assessed.

In September 2006, the FASB issued Statement No. 157 (FAS 157), “Fair Value Measurements”. FAS 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of FAS 157 on our statement of income, financial condition and cash flows.

In February 2007, the FASB issued Statement No. 159 (FAS 159), “The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115”, which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. We are currently assessing the impact of FAS 159 on our statement of income, financial condition and cash flows.

RESULTS OF OPERATIONS

Quarter Ended September 30, 2007 versus Quarter Ended September 30, 2006

Provided below is a comparison of selected operating and financial data for the third quarter of 2007 versus the third quarter of 2006:

		Quarter Ended September 30, 2007		Quarter Ended September 30, 2006	Percent Change
Total Revenue	$	286,335,000	$	299,894,000	(5)%
Net Income	$	64,061,000	$	81,265,000	(21)%
Drilling:					
Revenue	$	157,769,000	$	182,461,000	(14)%
Operating costs excluding depreciation	$	77,951,000	$	78,595,000	(1)%
Percentage of revenue from daywork contracts		100%		100%	—%
Average number of rigs in use		100.3		110.6	(9)%
Average dayrate on daywork contracts	$	18,470	$	19,559	(6)%
Depreciation	$	14,793,000	$	13,403,000	10%
Oil and Natural Gas:					
Revenue	$	95,231,000	$	91,238,000	4%
Operating costs excluding depreciation, depletion and amortization	$	23,101,000	$	21,560,000	7%
Average natural gas price (Mcf)	$	5.77	$	6.02	(4)%
Average oil price (Bbl)	$	62.01	$	59.55	4%
Natural gas production (Mcf)		11,206,000		11,200,000	—%
Oil production (Bbl)		470,000		376,000	25%
Depreciation, depletion and amortization rate (Mcfe)	$	2.29	$	2.04	12%
Depreciation, depletion and amortization	$	32,297,000	$	27,557,000	17%
Gas Gathering and Processing:					
Revenue	$	32,784,000	$	25,638,000	28%
Operating costs excluding depreciation and amortization	$	28,275,000	$	22,216,000	27%
Depreciation and amortization	$	2,858,000	$	1,637,000	75%
Gas gathered – MMbtu/day		221,508		276,888	(20)%
Gas processed – MMbtu/day		55,721		35,124	59%
Gas liquids sold – Gallons/day		137,098		71,790	91%
General and Administrative Expense	$	5,355,000	$	4,630,000	16%
Interest Expense	$	1,797,000	$	1,228,000	46%
Income Tax Expense	$	35,847,000	$	47,803,000	(25)%
Average Interest Rate		6.08%		6.04%	1%
	$	182,385,000	$	131,948,000	38%

Average Long-Term Debt
Outstanding

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Drilling

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first nine months of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with the high levels of natural gas storage throughout the majority of the winter season and again this summer. Drilling revenues decreased $24.7 million or 14% in the third quarter of 2007 versus the third quarter of 2006. Since the second quarter of 2006, we have placed 13 additional drilling rigs into service. We have constructed four drilling rigs and in June 2007 we acquired nine drilling rigs. Nine of these additional drilling rigs provided contract drilling services in the third quarter of 2007 increasing drilling revenues by $12.7 million or 7% of total drilling revenues in the third quarter of 2006. Revenues for rigs previously owned declined $37.4 million or 21% of the revenues in the third quarter of 2006 and more than offset the increase in revenue from rigs added subsequent to the third quarter of 2006. Average rig utilization declined from 110.6 rigs in the third quarter of 2006 to 100.3 in the third quarter of 2007. The decline in rig utilization decreased drilling revenues by $17.0 million while decreases in revenue per day between the comparative third quarters decreased revenue by $7.7 million. Our average dayrate in the third quarter of 2007 was 6% lower than in the third quarter of 2006. Utilization for our drilling rigs was 78% in the third quarter 2007 and we anticipate it to remain around 80% through early 2008. With decreases in drilling rig demand, we experienced a 1% decline in the third quarter 2007 average dayrate compared to the second quarter 2007 average dayrate and we anticipate average dayrates to continue to decline through early 2008.

Drilling operating costs decreased $0.6 million or 1% between the comparative quarters. Operating cost decreased as a result of 10 fewer rigs operating between the comparative quarters. This decrease was offset by an increase in operating cost of $721 per day in the third quarter of 2007 when compared with the third quarter of 2006 which includes $190 per day from a $1.8 million recognition of bad debt expense. The majority of the increases in cost per day were attributable to the increases in indirect drilling cost, truck expense and yard expense as the cost for services supporting our rig fleet continue to increase. With continued competition for qualified labor and utilization continuing around the 80% level, we expect our drilling rig expense per day to remain steady or increase slightly over the remainder of 2007. Contract drilling depreciation increased $1.4 million or 10%. The addition of the 13 drilling rigs placed in service since the second quarter of 2006 and additional assets acquired in the 2007 second quarter rig acquisition increased depreciation with the increase partially offset by the effect of decreased utilization.

Oil and Natural Gas

Oil and natural gas revenues increased $4.0 million or 4% in the third quarter of 2007 as compared to the third quarter of 2006 due to an increase in equivalent production volumes of 4% and an increase in average oil prices. The increases were partially offset by decreased natural gas prices. Average natural gas prices between the comparative quarters decreased 4% to $5.77 per Mcf while oil prices increased 4% to $62.01 per barrel. In the third quarter of 2007, natural gas production increased by less than 1% while oil production increased 25%. Increased natural gas and oil production came primarily from our ongoing development drilling activity and from acquisitions completed in 2006. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2007 compared to 2006 will increase 4% to 5%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $1.5 million or 7% in the third quarter of 2007 as compared to the third quarter of 2006. An increase in the average cost per equivalent Mcf produced represented 30% of the increase in production costs with the remaining 70% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Increases in general and administrative expenses directly related to oil and natural gas production along with increases in lease operating expenses caused most of the operating cost increase. These increases were partially offset by a 15% decrease in gross production taxes. Lease operating expenses per Mcfe remained constant between the comparative quarters. Gross production taxes decreased due to the decline in average natural gas prices used to compute gross production taxes which exclude the effect of our hedging activity. General and administrative expenses increased as labor costs increased primarily due to a 26% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization ("DD&A") increased $4.7 million or 17%. Higher production volumes accounted for 25% of the increase while increases in our DD&A rate represented 75% of the increase. The increase in our DD&A rate in the third quarter of 2007 compared to the third quarter of 2006 resulted primarily from an 18% increase in our finding cost in 2006. Increasing demand for drilling rigs prior to the fourth quarter of 2006

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throughout our areas of exploration increased the dayrates we pay to drill wells in our developmental program. Increases in natural gas and oil prices over the last two years have also caused increased sales prices for producing property acquisitions and even with the increased sales prices, we continue to see strong competition for producing property acquisitions.

Mid-Stream

Our mid-stream segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate four natural gas treatment plants and own seven operating processing plants, 36 active gathering systems and 651 miles of pipeline. These operations are conducted in Oklahoma, Texas, Louisiana and Kansas. Intercompany revenue from services and purchases of production between our natural gas gathering and processing segment and our oil and natural gas segments has been eliminated. Our mid-stream revenues were $7.1 million or 28% higher in the third quarter of 2007 as compared to the third quarter of 2006 due to the higher volumes of natural gas liquids sold and processed combined with higher liquids prices slightly offset by lower natural gas prices. The average price for liquids sold was 12% higher slightly offset by the average gas sold which was 2% lower. Gas processing volumes per day increased 59% between the comparative quarters and gas liquids sold per day increased 91% between the comparative quarters. A 20% decrease in gathering volumes per day partially offset the increase in revenue from natural gas sales and processing. The significant increase in volumes processed per day is primarily attributable to the acquisition of a processing plant in September of 2006 and to a lesser extent volumes from wells added to existing systems throughout 2006. Gas liquids sold volumes per day increased due to recent upgrades to several of our processing facilities. Natural gas liquids sales were reduced $0.6 million due to our natural gas liquids swaps.

Operating costs increased 27% in the third quarter of 2007 compared with the third quarter of 2006 due to a 40% increase in natural gas volumes purchased, slightly offset by a 2% decrease in prices paid for natural gas purchased, a 41% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas processed and a 13% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 13%. The 75% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Gas gathering volumes per day in the third quarter of 2007 were up 2% compared to the second quarter of 2007 primarily due to increased well connections. Gas processing volumes per day in the third quarter of 2007 were up 31% and gas liquids sold were up 20% compared to the second quarter of 2007. Operating costs were increased $1.1 million in the third quarter of 2007 due to our natural gas purchases hedge.

Other

General and administrative expense increased $0.7 million in the third quarter of 2007 compared to the third quarter of 2006. The increase in cost was primarily from a 16% increase in the number of employees associated with the growth of the company and the increases in employee compensation cost.

Total interest expense increased 46% between the comparative quarters. Average debt outstanding was 38% higher in the third quarter of 2007 as compared to the third quarter of 2006 primarily due to the acquisition of producing properties in the last four months of 2006 and the acquisition of a drilling company in the second quarter of 2007. Average debt outstanding accounted for approximately 98% of the interest expense increase, with the remaining 2% resulting from an increase in average interest rates on our bank debt. Interest expense was reduced $0.2 million from the settlements of our interest rate swap. Associated with our increased level of development of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $1.1 million of interest in the third quarter of 2007 compared with $0.9 million in the third quarter of 2006.

Income tax expense decreased $12.0 million or 25% due primarily to the decrease in income before income taxes. Our effective tax rate for the third quarter of 2007 was 35.9% versus 37.0% in the third quarter of 2006 due primarily to the increase in manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense for the third quarter of 2007 was $11.2 million or 31% of total income tax expense as compared with $26.4 million or 55% of total income tax expense in the third quarter of 2006. The reduction in the percentage of tax expense recognized as current is the result of increased intangible drilling costs to be deducted in the current year. Income taxes paid in the third quarter of 2007 were $15.7 million.

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Nine Months Ended September 30, 2007 versus Nine Months Ended September 30, 2006

Provided below is a comparison of selected operating and financial data for the first nine months of 2007 versus the first nine months of 2006:

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Percent Change
Total Revenue	$ 850,246,000	$ 863,051,000	(1)%
Net Income	$ 194,109,000	$ 230,995,000	(16)%
Drilling:			
Revenue	$ 472,403,000	$ 519,799,000	(9)%
Operating costs excluding depreciation	$ 228,967,000	$ 238,021,000	(4)%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of rigs in use	98.4	109.8	(10)%
Average dayrate on daywork contracts	$ 18,858	$ 18,442	2%
Depreciation	$ 41,192,000	$ 38,089,000	8%
Oil and Natural Gas:			
Revenue	$ 277,680,000	$ 267,518,000	4%
Operating costs excluding depreciation, depletion and amortization	$ 69,701,000	$ 58,854,000	18%
Average natural gas price (Mcf)	$ 6.30	$ 6.28	—%
Average oil price (Bbl)	$ 54.90	$ 57.18	(4)%
Natural gas production (Mcf)	32,507,000	32,350,000	—%
Oil production (Bbl)	1,260,000	1,062,000	19%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.29	$ 1.97	16%
Depreciation, depletion and amortization	$ 92,367,000	$ 76,780,000	20%
Gas Gathering and Processing:			
Revenue	$ 99,321,000	$ 72,840,000	36%
Operating costs excluding depreciation, and amortization	$ 87,171,000	$ 63,734,000	37%
Depreciation and amortization	$ 7,752,000	$ 4,019,000	93%
Gas gathered – MMbtu/day	221,943	245,435	(10)%
Gas processed – MMbtu/day	47,432	27,226	74%
Gas liquids sold – Gallons/day	115,781	57,840	100%
General and Administrative Expense	$ 15,784,000	$ 12,998,000	21%
Interest Expense	$ 5,167,000	$ 3,235,000	60%
Income Tax Expense	$ 108,036,000	$ 136,326,000	(21)%
Average Interest Rate	6.10%	5.76%	6%
Average Long-Term Debt Outstanding	$ 175,408,000	$ 121,323,000	45%

Drilling

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into the first nine months of 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with the high levels of natural gas storage throughout the majority of the winter season and again this summer. Drilling revenues decreased $47.4 million or 9% in the first nine months of 2007 versus the first nine months of 2006. Since February 2006, we have placed 16 additional drilling rigs into service. We have constructed seven drilling rigs and in June 2007 we acquired nine drilling rigs. Thirteen of these additional drilling rigs provided contract drilling services in the first nine months of 2007 increasing drilling revenues by $27.7 million or 5% of revenues in the first nine months of 2006. Revenues for rigs previously owned declined $75.1 million or 14% from revenues in the first nine months of 2006 and more than offset the increase in revenue from rigs added subsequent to the second quarter of 2006. Average rig utilization declined from 109.8 rigs in the first nine months of 2006 to 98.4 in the first nine months of 2007. The decline in rig utilization decreased drilling revenues by $54.3 million while increases in dayrates between the comparative nine months periods provided additional revenue of $6.9 million partially offsetting utilization decreases. Our average dayrate in the first nine months of 2007 was 2% higher than in the first nine months of 2006. Utilization for our drilling rigs was 81% for the first nine months of 2007 and we anticipate utilization around 80% through early 2008.

Drilling operating costs decreased $9.1 million or 4% between the comparative nine month periods. Operating cost decreased as a result of 11 fewer rigs operating between the comparative nine month periods. This decrease in operating cost was partially offset by an increase in operating cost per day of $589 in the first nine months of 2007 when compared with the first nine months of 2006 which includes $65 per day from a $1.8 million recognition of bad debt. The majority of the increase in cost per day was attributable to indirect drilling cost, truck expense and yard expense as the cost for services supporting our rig fleet continue to increase. Cost also increased, to a lesser extent, from increases in direct drilling cost. With continued competition for qualified labor and utilization continuing around the 80% level, we expect our drilling rig expenses per day to remain steady or increase slightly over the remainder of 2007. Contract drilling depreciation increased $3.1 million or 8%. The addition of the 16 drilling rigs placed in service since February 2006 and the additional assets acquired in the 2007 second quarter rig acquisition increased depreciation with the increase partially offset by the effect of decreased utilization.

Oil and Natural Gas

Oil and natural gas revenues increased $10.2 million or 4% in the first nine months of 2007 as compared to the first nine months of 2006 due to an increase in equivalent production volumes of 3% and a slight increase in average natural gas prices. The increases were partially offset by decreased oil prices. Average natural gas prices between the comparative nine month periods increased less than 1% to $6.30 per Mcf while oil prices declined 4% to $54.90 per barrel. In the first nine months of 2007, natural gas production increased by less than 1% while oil production increased 19%. Increased natural gas and oil production came primarily from our ongoing development drilling activity and from acquisitions completed in 2006. Production increases primarily in the first quarter of 2007 were limited due to the impact from a Texas refinery fire, adverse winter weather, pipeline construction delays preventing the connection of wells recently drilled and the timing of completion of certain wells. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2007 compared to 2006 will increase 4% to 5%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $10.8 million or 18% in the first nine months of 2007 as compared to the first nine months of 2006. An increase in the average cost per equivalent Mcf produced represented 79% of the increase in production costs with the remaining 21% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 69% of the increase, gross production taxes 8%, general and administrative cost directly related to oil and natural gas production 21% and increased accretion on plugging liability 2%. Lease operating expenses per Mcfe increased 16% between the comparative nine month periods as post production transportation cost, salt water disposal fees and compression increased along with a 59% increase in workover cost. Gross production taxes increased due to the increase in oil and natural gas volumes produced between the comparative quarters and the increase in natural gas prices. General and administrative expenses increased as labor costs increased primarily due to an 18% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization (“DD&A”) increased $15.6 million or 20%. Higher production volumes accounted for 17% of the increase while increases in our DD&A rate represented 83% of the increase. The increase

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in our DD&A rate in the first nine months of 2007 compared to the first nine months of 2006 resulted primarily from an 18% increase in our finding cost in 2006. Increasing demand for drilling rigs prior to the fourth quarter of 2006 throughout our areas of exploration increased the dayrates we pay to drill wells in our developmental program. Increases in natural gas and oil prices over the last two years have also caused increased sales prices for producing property acquisitions and even with the increased sales prices, we continue to see strong competition for producing property acquisitions.

Mid-Stream

Our mid-stream segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate four natural gas treatment plants and own seven operating processing plants, 36 active gathering systems and 651 miles of pipeline. These operations are conducted in Oklahoma, Texas, Louisiana and Kansas. Intercompany revenue from services and purchases of production between our natural gas gathering and processing segment and our oil and natural gas segments has been eliminated. Our mid-stream revenues were $26.5 million or 36% higher in the first nine months of 2007 as compared to the first nine months of 2006 due to the higher volumes of natural gas sales and processing combined with higher natural gas prices. The average price for gas sold was less than 1% higher and the average price for liquids sold was 5% higher. Gas processing volumes per day increased 74% between the comparative nine month periods and gas liquids sold per day increased 100% between the comparative nine month periods. A 10% decrease in gathering volumes per day as gas transportation prices remained unchanged partially offset the increase in revenue from natural gas sales and processing. The significant increase in volumes processed per day is primarily attributable to the acquisition of a processing plant in September of 2006 and to a lesser extent volumes from wells added to existing systems throughout 2006. Gas liquids sold volumes per day increased due to recent upgrades to several of our processing facilities. Natural gas liquids sales were reduced $0.6 million due to our natural gas liquids swaps.

Operating costs increased 37% in the first nine months of 2007 compared with the first nine months of 2006 due an to a 34% increase in natural gas volumes purchased, slightly offset by a less than 1% decrease in prices paid for natural gas purchased, a 65% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas processed and a 31% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 31%. The 93% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Gas gathering volumes per day for the first nine months of 2007 were down 10% compared to the first nine months of 2006 primarily due to a slow down of new well connections associated with adverse winter weather and pipeline construction delays primarily in the first quarter of 2007 and declining production rates on existing wells. Subsequent declines will continue until further field development results in new well connections. Gas processing volumes per day for the first nine months of 2007 were up 74% compared to the first nine months of 2006 primarily due to the purchase of a gas processing system in September of 2006 and the completion of another plant in July 2006. Operating costs were increased $1.1 million due to our natural gas purchases hedge.

Other

General and administrative expense increased $2.8 million in the first nine months of 2007 compared to the first nine months of 2006. The increase in cost was primarily from a 16% increase in the number of employees associated with the growth of the company and increases in employee compensation cost.

Total interest expense increased 60% between the comparative nine month periods. Average debt outstanding was 45% higher in the first nine months of 2007 as compared to the nine months of 2006 primarily due to the acquisition of producing properties in the last four months of 2006 and the acquisition of a drilling company in the second quarter of 2007. Average debt outstanding accounted for approximately 84% of the interest expense increase, with the remaining 16% resulting from an increase in average interest rates on our bank debt. Interest expense was reduced $0.5 million from settlements of our interest rate swap. Associated with our increased level of development of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $3.3 million of interest in the first nine months of 2007 compared with $2.5 million in the first nine months of 2006.

Income tax expense decreased $28.3 million or 21% due primarily to the decrease in income before income taxes. Our effective tax rate for the first nine months of 2007 was 35.8% versus 37.1% in the first nine months of

2006 with the change due primarily to the increase in manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense for the first nine months of 2007 was $53.5 million or 50% of total income tax expense in the first nine months of 2007 as compared with $89.7 million or 66% of total income tax expense in the first nine months of 2006. The reduction in the percentage of tax expense recognized as current is the result of increased intangible drilling costs to be deducted in the current year. Income taxes paid in the first nine months of 2007 were $58.2 million.

In January 2006, one of our drilling rigs was destroyed by a fire. No personnel were injured although the drilling rig was a total loss. Insurance proceeds for the loss exceeded our net book value and provided a gain of approximately $1.0 million which is recorded in other revenues.

SAFE HARBOR STATEMENT

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

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

- the amount and nature of our future capital expenditures;
- the amount of wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- our exploration prospects;
- estimates of our proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas reserves;
- growth potential for our mid-stream operations;
- gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations; and
- demand for our drilling rigs and drilling rig rates.

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

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

- demand for our land drilling services;
- changes in laws or regulations; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

Our operations are exposed to market risks primarily as a result of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, the prices we received for our oil and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first nine months of 2007 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $338,000 per month ($4.1 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $131,000 per month ($1.6 million annualized) change in our pre-tax operating cash flow.

In an effort to try and reduce the impact of price fluctuations, over the past several years we have periodically used hedging strategies to hedge the price we will receive for a portion of our future oil and natural gas production. A detailed explanation of those transactions has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above.

In an effort to try and reduce the impact of price fluctuations received for natural gas liquids, in June 2007 we entered into a series of natural gas liquid sales and natural gas purchase swaps to effectively lock in the fractionation spread we receive on approximately 65% of our liquids processed and sold. A detailed explanation of those transactions has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. In February 2005, we entered into an interest rate swap for $50.0 million of our outstanding debt to help manage our exposure to any future interest rate volatility and in October 2007 we added an additional $15.0 million interest rate swap. A detailed explanation of this transaction has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operations included above. Based on our average outstanding long-term debt subject to the floating rate in the first nine months of 2007, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $1.3 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of September 30, 2007 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, 2007 that could significantly affect these internal controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The company is a party to certain litigation arising in the ordinary course of its business. Although the amount of any liability that could arise with respect to these actions cannot be accurately predicted, in the company's opinion, any such liability will not have a material adverse effect on our business, financial condition and/or operating results.

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2006, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2006.

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

Not applicable

Item 3. Defaults Upon Senior Securities

Not applicable

Item 4. Submission of Matters to a Vote of Security Holders

Not applicable

Item 5. Other Information

Not applicable

Item 6. Exhibits

Exhibits:

10.2.48	Separation Benefit Plan of Unit Corporation and Participating Subsidiaries as amended, effective August 21, 2007.
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.

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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, 2007	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: November 1, 2007	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer