UNIT CORP
Form 10-Q
November 02, 2006

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, 2006

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 November 1, 2006, 46,278,990 shares of the issuer's common stock were outstanding.

FORM 10-Q
UNIT CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS (UNAUDITED)

	September 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 606	$ 947
Restricted cash	18	268
Accounts receivable	203,535	199,765
Materials and supplies	23,152	14,108
Other	16,660	8,597
Total current assets	243,971	223,685
Property and Equipment:		
Drilling equipment	742,623	626,913
Oil and natural gas properties, on the full cost method:		
Proved properties	1,191,130	995,119
Undeveloped leasehold not being amortized	51,164	38,421
Gas gathering and processing equipment	80,490	60,354
Transportation equipment	19,951	17,338
Other	16,030	12,935
	2,101,388	1,751,080
Less accumulated depreciation, depletion, amortization and impairment	689,028	575,410
Net property and equipment	1,412,360	1,175,670
Goodwill	39,659	39,659
Other Intangible Assets, Net	17,739	---
Other Assets	13,103	17,181
Total Assets	$ 1,726,832	$ 1,456,195

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

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

	September 30, 2006	December 31, 2005
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 90,124	$ 109,621
Accrued liabilities	35,727	32,819
Income taxes payable	2,863	16,941
Contract advances	10,677	5,548
Current portion of other liabilities	7,820	7,583
Total current liabilities	147,211	172,512
Long-Term Debt	145,100	145,000
Other Long-Term Liabilities	53,710	41,981
Deferred Income Taxes	306,250	259,740
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	---	---
Common stock, $.20 par value, 175,000,000 and 75,000,000 authorized, 46,278,990 and 46,178,162 shares issued, respectively	9,256	9,236
Capital in excess of par value	332,389	328,037
Accumulated other comprehensive income	491	485
Unearned compensation - restricted stock	---	(2,226)
Retained earnings	732,425	501,430
Total shareholders' equity	1,074,561	836,962
Total Liabilities and Shareholders' Equity	$ 1,726,832	$ 1,456,195

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

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

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 182,461	$ 119,873	$ 519,799	$ 322,379
Oil and natural gas	91,238	83,979	267,518	202,819
Gas gathering and processing	25,638	26,561	72,840	65,895
Other	557	635	2,894	1,402
Total revenues	299,894	231,048	863,051	592,495
Expenses:				
Contract drilling:				
Operating costs	78,595	67,161	238,021	194,890
Depreciation	13,403	11,019	38,089	31,010
Oil and natural gas:				
Operating costs	21,560	15,913	58,854	40,916
Depreciation, depletion and amortization	27,557	16,355	76,780	45,632
Gas gathering and processing:				
Operating costs	22,216	24,395	63,734	60,616
Depreciation and amortization	1,637	902	4,019	2,267
General and administrative	4,630	3,324	12,998	10,455
Interest	1,228	885	3,235	2,157
Total expenses	170,826	139,954	495,730	387,943
Income Before Income Taxes	129,068	91,094	367,321	204,552
Income Tax Expense:				
Current	26,442	19,628	89,741	41,185
Deferred	21,361	13,828	46,585	35,385
Total income taxes	47,803	33,456	136,326	76,570
Net Income	$ 81,265	$ 57,638	$ 230,995	$ 127,982
Net Income per Common Share:				
Basic	$ 1.76	$ 1.25	$ 5.00	$ 2.79
Diluted	$ 1.75	$ 1.25	$ 4.98	$ 2.78

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

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

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 230,995	$ 127,982
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion and amortization	119,422	79,520
Deferred tax expense	46,585	35,385
Other	5,843	2,647
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(4,840)	(47,742)
Accounts payable	(27,424)	(17,892)
Material and supplies inventory	(9,044)	1,200
Accrued liabilities	(9,139)	8,638
Contract advances	5,129	1,009
Other - net	(7,928)	(895)
Net cash provided by operating activities	349,599	189,852
Cash Flows From (Used In) Investing Activities:		
Capital expenditures	(299,312)	(222,157)
Cash paid for acquisitions	(53,820)	---
Proceeds from disposition of assets	5,865	4,772
Other-net	(241)	(4,627)
Net cash used in investing activities	(347,508)	(222,012)
Cash Flows From (Used In) Financing Activities:		
Borrowings under line of credit	183,200	161,800
Payments under line of credit	(183,100)	(141,700)
Net change in other long-term liabilities	---	181
Proceeds from exercise of stock options	726	1,128
Tax Benefit from stock options	290	---
Book overdrafts	(3,548)	10,814
Net cash from (used in) financing activities	(2,432)	32,223
Net Increase (Decrease) in Cash and Cash Equivalents	(341)	63
Cash and Cash Equivalents, Beginning of Year	947	665
Cash and Cash Equivalents, End of Period	$ 606	$ 728

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)			
Net Income	$ 81,265	$ 57,638	$ 230,995	$ 127,982
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	(106)	(1,901)	273	(2,353)
Reclassification - derivative settlements	(148)	786	(267)	888
Comprehensive Income	$ 81,011	$ 56,523	$ 231,001	$ 126,517

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

NOTE 1 - BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The accompanying unaudited consolidated condensed financial statements include the accounts of Unit Corporation and its directly or indirectly wholly owned subsidiaries (company) and have been prepared under the rules and regulations of the Securities and Exchange Commission (SEC). As applicable under these regulations, certain information and footnote disclosures have been condensed or omitted and the consolidated condensed financial statements do not include all disclosures required by accounting principles generally accepted in the United States of America. In the opinion of the company, the unaudited consolidated condensed financial statements contain all adjustments necessary (all adjustments are of a normal recurring nature) to state fairly the interim financial information.

Results for the three months and nine months ended September 30, 2006 are not necessarily indicative of the results to be realized during the full year. The consolidated condensed financial statements should be read with the company’s Annual Report on Form 10-K for the year ended December 31, 2005. With respect to the unaudited financial information of the company for the three and nine month periods ended September 30, 2006 and 2005, included in this Form 10-Q, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards for a review of such information. However, its separate report dated, November 2, 2006 appearing herein, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on its report on that information 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 the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

Stock Based Compensation. Before January 1, 2006, the company accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25, “Accounting for Stock Issued to Employees,” and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, the company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. The company elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. 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, will be recognized in the company's 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. The company utilizes the Black-Scholes option pricing model to measure the fair value of stock options. Before the adoption of FAS 123(R), the company followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Financial statements for prior periods have not been restated.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, with the adoption of FAS 123(R) we eliminated $2.2 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our condensed consolidated balance sheet.

The following table illustrates, for the three month and nine month periods ending September 30, 2005, the effect on net income and earnings per share if the company had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation. Compensation expense included in reported net income before January 1, 2006 is the company's matching 401(k) contribution.

	Three Months Ended September 30, 2005		Nine Months Ended September 30, 2005	
	(In thousands except per share amounts)			
Net Income, as Reported	$	57,638	$	127,982
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax		397		1,344
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards		(956)		(2,877)
Pro Forma Net Income	$	57,079	$	126,449
Basic Earnings per Share:				
As reported	$	1.25	$	2.79
Pro forma	$	1.24	$	2.76
Diluted Earnings per Share:				
As reported	$	1.25	$	2.78
Pro forma	$	1.23	$	2.74

In the third quarter and first nine months of 2006, the company recognized stock compensation cost for stock bonus 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 remaining unrecognized compensation cost related to unvested awards at September 30, 2006 is approximately $2.6 million with $0.7 million of this amount to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

No options were granted during the three month periods ending September 30, 2006 and 2005. The following table estimates the fair value of each option granted during the nine month periods ending September 30, 2006 and 2005 using the Black-Scholes model applying the estimated values presented in the table:

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Options Granted	33,000	58,500
Estimated Fair Value (In Millions)	$ 0.8	$ 1.3
Estimate of Stock Volatility	0.38	0.51 to 0.55
Estimated Dividend Yield	0%	0%
Risk Free Interest Rate	5.00%	4.35 to% 4.42
Expected Life Range Based on Prior Experience (In Years)	3 to 7	6 to 10

Expected volatilities are based on the historical volatility of the company's stock. The company uses historical data to estimate 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, the company has not paid dividends on its 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.

At the company's annual meeting on May 3, 2006, the company's shareholders approved the Unit Corporation Stock and Incentive Compensation Plan. This plan allows for the issuance of 2.5 million shares of common stock with 2.0 million shares being the maximum number of shares that can be issued as "incentive stock options." Awards under this plan may be granted in any one or a combination of the following:

- incentive stock options under Section 422 of the Internal Revenue Code;
- non-qualified stock options;
- performance shares;
- performance units;
- restricted stock;
- restricted stock units;
- stock appreciation rights;
- cash based awards; and
- other stock-based awards.

This plan also contains various limits as to the amount of awards that can be given to an employee in any fiscal year. All awards shall be subject to the minimum vesting periods, as determined by the company's Compensation Committee and included in the award agreement. At September 30, 2006 no award had been granted under this plan.

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan. Under this plan 330,950 shares of common stock were reserved for issuance. On May 3, 1995, the company's shareholders approved and amended the plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the plan. Under the terms of the plan, awards were granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in installments subject to certain restrictions. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan at the company's annual meeting on May 3, 2006, no further grants will be made under the plan. No shares were issued under the plan in 2003 and 2004. On December 13, 2005, 38,190 shares (in the form of restricted stock awards) were granted under the plan.

The company also has a Stock Option, which provided for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The option plan permitted the issuance of qualified or nonqualified stock options. Options granted typically become exercisable at the rate of 20% per year one year after being granted and expire after 10 years from the original grant date. The exercise price for options granted under this plan is the fair market value of the common stock on the date of the grant. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan, no further awards will be made under the option plan.

Activity pertaining to the Option Plan is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Number of Shares:				
Outstanding at Beginning of Period	390,470	467,913	434,713	553,750
Granted	---	---	5,000	34,000
Exercised	(3,320)	(18,121)	(52,563)	(87,558)
Forfeited	(800)	(11,400)	(800)	(61,800)
Outstanding at End of Period	386,350	438,392	386,350	438,392
Weighted Average Exercise Price:				
Outstanding at Beginning of Period	$ 25.67	$ 23.98	$ 24.14	$ 22.11
Granted	---	---	55.83	37.16
Exercised	21.54	17.71	15.61	15.92
Forfeited	37.83	30.86	37.83	25.03
Outstanding at End of Period	$ 25.68	$ 24.11	$ 25.68	$ 24.11

The intrinsic value of options exercised in the third quarter and first nine months of 2006 was $0.1 million and $2.3 million, respectively. Options totaling 1,000 and 7,600 shares vested during the third quarter and first nine months of 2006, respectively. Total cash received from the options exercised in the third quarter and first nine months of 2006 was $0.1 million and $0.7 million, respectively.

	Outstanding Options Under The Stock Option Plan At September 30, 2006		
Exercise Prices	**Number of Shares**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**
$3.75	34,000	2.2 years	$ 3.75
$8.75	2,500	0.2 years	$ 8.75

$16.69 - $19.04	112,600	5.6 years	$	18.33
$21.50 - $26.28	89,810	7.2 years	$	22.96
$34.75 - $37.83	142,440	8.3 years	$	37.68
$53.90 - $60.32	5,000	9.5 years	$	55.83

The aggregate intrinsic value of the 386,350 shares outstanding subject to option at September 30, 2006 was $7.8 million with a weighted average remaining contractual term of 6.7 years.

	Exercisable Options Under The Stock Option Plan At September 30, 2006		
Exercise Prices	**Number of Shares**		**Weighted Average Exercise Price**
$3.75	34,000	$	3.75
$8.75	2,500	$	8.75
$16.69 - $19.04	73,800	$	17.96
$21.50 - $26.28	32,700	$	22.82
$34.75 - $37.83	26,840	$	37.67
$53.90 - $60.32	---	$	---

Options for 169,840 and 142,212 shares were exercisable with weighted average exercise prices of $19.03 and $13.71 at September 30, 2006 and 2005, respectively. The aggregate intrinsic value of shares exercisable at September 30, 2006 was $4.6 million with a weighted average remaining contractual term of 5.4 years.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan. Under the plan, on the first business day following each annual meeting of shareholders, each person who was then a member of the Board of Directors of Unit and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. In February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan, which replaced the prior plan. Under the new plan an aggregate of 300,000 shares of common stock may be issued on exercise of the stock options. Commencing with the year 2000 annual meeting, the amount granted increased to 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. The term of each option is 10 years and cannot be increased and no stock options may be exercised during the first six months of its term except in case of death.

Activity pertaining to both of the Directors' Plans is as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2006		**2005**		**2006**		**2005**
Number of Shares:								
Outstanding at Beginning of Period		120,500		112,500		96,000		94,000
Granted		---		---		28,000		24,500
Exercised		---		(13,000)		(3,500)		(19,000)
Forfeited		---		---		---		---
Outstanding at End of Period		120,500		99,500		120,500		99,500
Weighted Average Exercise Price:								
Outstanding at Beginning of Period	$	33.78	$	24.84	$	24.93	$	20.27

Granted	---	---	62.40	39.50
Exercised	---	20.25	20.10	17.99
Forfeited	---	---	---	---
Outstanding at End of Period	$ 33.78	$ 25.44	$ 33.78	$ 25.44

The intrinsic value of options exercised in the first nine months of 2006 was $0.1 million. No options were exercised in the third quarter of 2006 and no options vested during the third quarter and first nine months of 2006. Total cash received from options exercised in the first nine months of 2006 was $0.1 million.

	Outstanding Options Under The Directors' Plans At September 30, 2006			
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life		Weighted Average Exercise Price
$6.90	5,000	2.6 years	$	6.90
$12.19 - $17.54	14,000	4.3 years	$	16.20
$20.10 - $20.46	31,500	6.1 years	$	20.30
$28.23 - $39.50	42,000	8.1 years	$	33.87
$62.40	28,000	9.4 years	$	62.40

The aggregate intrinsic value of the 120,500 shares outstanding subject to options at September 30, 2006 was $1.5 million with a weighted average remaining contractual term of 7.3 years.

	Exercisable Options Under The Directors' Plans At September 30, 2006		
Exercise Prices	Number of Shares		Weighted Average Exercise Price
$6.90	5,000	$	6.90
$12.19 - $17.54	14,000	$	16.20
$20.10 - $20.46	31,500	$	20.30
$28.23 - $39.50	42,000	$	33.87
$62.40	---	$	---

Options for 92,500 and 75,000 shares were exercisable with weighted average exercise prices of $25.11 and $20.85 at September 30, 2006 and 2005, respectively. The aggregate intrinsic value of shares exercisable at September 30, 2006 was $1.9 million with a weighted average remaining term of 6.6 years.

Oil and Natural Gas Operations. The company accounts for its oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. Under the full cost rules, at the end of each quarter, the company reviews the carrying value of its oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from the company's oil and natural gas properties discounted at 10%. Full cost companies are required to use the unescalated prices in effect as of the end of each fiscal quarter to calculate the discounted future revenues. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs, even if prices are depressed for only a short period of time. Under the SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

In the third quarter of 2006, natural gas prices declined significantly. The unescalated prices used to calculate the company's reserves at September 30, 2006 for purposes of the ceiling test were $3.86 per Mcf for natural gas, $62.91 per Bbl for oil and $39.53 per Bbl for natural gas liquids. As a result, the ceiling test as of September 30, 2006 indicated an impairment of the oil and natural gas properties of approximately $20.9 million, net of income taxes. However, natural gas prices subsequent to September 30, 2006, have improved sufficiently to eliminate this calculated impairment. As a result, the company is not required to record a write-down of its oil and natural gas properties under the full cost method of accounting in the third quarter. Since oil and natural gas prices remain volatile, the company may be required to write down the carrying value of its oil and natural gas properties at the end of future reporting periods. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

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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, 2006:					
Basic earnings per common share	$	81,265	46,241	$	1.76
Effect of dilutive stock options and restricted stock bonus shares		---	203		(0.01)
Diluted earnings per common share	$	81,265	46,444	$	1.75
For the Three Months Ended September 30, 2005:					
Basic earnings per common share	$	57,638	45,959	$	1.25
Effect of dilutive stock options		---	270		---
Diluted earnings per common share	$	57,638	46,229	$	1.25

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended September 30, 2006 and 2005 because the option exercise prices were greater than the average market price of the common stock:

		2006		2005
Options		33,000		---
Average Exercise Price	$	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, 2006:			
Basic earnings per common share	$ 230,995	46,223	$ 5.00
Effect of dilutive stock options and restricted stock bonus shares	---	206	(0.02)
Diluted earnings per common share	$ 230,995	46,429	$ 4.98
For the Nine Months Ended September 30, 2005:			
Basic earnings per common share	$ 127,982	45,873	$ 2.79
Effect of dilutive stock options	---	235	(0.01)
Diluted earnings per common share	$ 127,982	46,108	$ 2.78

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the nine months ended September 30, 2006 and 2005 because the option exercise prices were greater than the average market price of the common stock:

	2006	2005
Options	29,500	---
Average Exercise Price	$ 62.29	$ ---

NOTE 3 - ACQUISITIONS

On May 16, 2006, the company’s wholly owned subsidiary, Unit Petroleum Company, announced it had 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 acquired with this acquisition consisted of approximately 14.2 Bcfe. This acquisition had an effective date of April 1, 2006. The $32.4 million paid in this acquisition increased the company's basis in oil and natural gas properties.

In September 2006, the company's wholly owned subsidiary, Superior Pipeline Company, L.L.C., closed its acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal assets of the acquired company consist of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. The purchase had an effective date of July 31, 2006. The financial results of the acquisition are included in the company's results of operations from September 1, 2006 forward with the results for the period from August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price. The $21.7 million acquisition price for Berkshire Energy LLC was allocated as follows (in thousands):

Working Capital	$ 337
Processing Plant and Gathering System	3,422
Amortizable Intangible Assets	17,957
Total Consideration	$ 21,716

As part of the acquisition, the company acquired long-term contracts for the gathering and processing of natural gas that will flow through this gathering system, the value of which is reported as an amortizable intangible asset. The capitalized value of these contracts and associated customer relationship will be amortized over an estimated life of 7 years. Aggregate amortization expense for this intangible asset for the quarter and nine months ended September 30, 2006 was $0.2 million. The total estimated amortization of intangible assets for the remainder of 2006 and the five succeeding years is $0.6 million, $3.3 million, $4.4 million, $3.8 million, $2.6 million and $1.2 million.

NOTE 4 - CREDIT AGREEMENT

As of September 30, 2006 and December 31, 2005, long-term debt under our credit facility consisted of the following:

	September 30, 2006	**December 31, 2005**
	(In thousands)	
Revolving Credit Facility, with Interest at September 30, 2006 and December 31, 2005 of 5.6% and 4.9%, Respectively	$ 145,100	$ 145,000
Less Current Portion	--	--
Total Long-Term Debt	$ 145,100	$ 145,000

At September 30, 2006, the company had a revolving $235.0 million credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount. Effective September 15, 2006, the company elected to increase the commitment amount available from $175.0 million to $200.0 million. The company is charged a commitment fee of .375 of 1% on the amount available but not borrowed. The company incurred origination, agency and syndication fees of $515,000 at the inception of the credit facility. During 2005, in connection with the amending of the credit facility, the company incurred additional origination, agency and syndication fees of $187,500. These fees are being amortized over the remaining life of the credit facility. The average interest rate for the third quarter and first nine months of 2006, including the effect of the interest swap transaction entered into by the company, was 6.0% and 5.8%, respectively. At September 30, 2006 and October 30, 2006, borrowings were $145.1 million and $170.6 million, respectively.

The borrowing base under the credit facility is subject to re-determination on May 10 and November 10 of each year. The latest redetermination supported the full $235.0 million. Each re-determination is based primarily on a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. The determination of the company's borrowing base also includes an amount representing a small part of the value of the company's drilling rig fleet (limited to $20 million) as well as such loan value as the banks reasonably attribute to Superior Pipeline Company's cash flow as defined in the credit facility agreement. The credit facility agreement allows for one requested special re-determination of the borrowing base by either the banks or the company between each regularly scheduled re-determination date.

Effective October 10, 2006, the company (including certain of its subsidiaries) and its Banks entered into a Third Amendment to its existing credit facility agreement. In general, this amendment modified the existing credit facility agreement by amending each of the Bank's Aggregate Commitment and the Maximum Credit Amount (each as defined in the credit facility agreement) from $235 million to the maximum principal amount $275. A facility fee of $60,000 was incurred with the signing of this amendment. This fee will be amortized over the remaining term of the credit facility.

At the company's election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which the LIBOR Rate option applies may be repaid on three days prior notice and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR Rate is computed at the LIBOR Base Rate applicable for the interest period plus 1.00% to 1.50% depending on the level of debt as a percentage of the total loan value and payable at the end of each term or every 90 days whichever is less. Borrowings not under the LIBOR Rate bear interest at the JPMorgan Chase 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, 2006, all of the $145.1 million we had borrowed was subject to the LIBOR rate.

The credit facility agreement 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 banks.

The credit agreement also requires the company to have at the end of each quarter:

• consolidated net worth of at least $350 million,
• a current ratio (as defined in the credit agreement) of not less than 1 to 1, and

• a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit agreement)for themost recently ended rolling four fiscal quarters of not greater than 3.25 to 1.0.

On September 30, 2006, the company was in compliance with the credit agreement covenants.

Other long-term liabilities of the company consisted of the following:

	September 30, 2006	December 31, 2005
	(In thousands)	
Separation Benefit Plan	$ 2,983	$ 2,788
Deferred Compensation Plan	2,547	2,611
Retirement Agreement	1,484	1,676
Workers' Compensation	21,590	19,394
Gas Balancing Liability	1,080	1,080
Plugging Liability	31,846	22,015
	61,530	49,564
Less Current Portion	7,820	7,583
Total Other Long-Term Liabilities	$ 53,710	$ 41,981

Estimated annual principle payments under the credit facility for long-term debt as well as for other long-term liabilities for the twelve month periods beginning October 1, 2006 through 2010 are $7.8 million, $151.3 million, $1.8 million, $1.7 million and $2.1 million. Based on the borrowing rates currently available to the company for debt with similar terms and maturities, long-term debt at September 30, 2006 approximates its fair value.

NOTE 5 - ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) the company must record the fair value of liabilities associated with the retirement of long-lived assets. The company owns oil and natural gas wells 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). The company does not have any assets restricted for the purpose of settling these liabilities.

The following table shows the activity for the nine months ending September 30, 2006 and 2005 relating to the company's retirement obligation for plugging liability:

	Nine Months Ended September 30. 2006	2005
	(In Thousands)	
Short-Term Plugging Liability:		
Liability at beginning of period	$ 366	$ 226
Accretion of discount	6	13
Liability incurred or assumed in the period	1	---
Liability settled in the period	(156)	(145)
Reclassification of liability from long-term to short-term	456	247
Revision of estimates	(30)	---
Plugging liability at end of period	$ 643	$ 341
Long-Term Plugging Liability:		
Liability at beginning of period	$ 21,649	$ 18,909
Accretion of discount	1,085	699
Liability incurred or assumed in the period	2,834	1,295
Reclassification of liability from long-term to short-term	(456)	(247)
Revision of estimates	6,091	(833)
Plugging liability at end of period	$ 31,203	$ 19,823

NOTE 6 - NEW ACCOUNTING PRONOUNCEMENTS

In December 2004, the Financial Accounting Standards Board ("FASB") issued FAS 123R "Share-Based Payment" (FAS 123(R)), which requires that compensation cost relating to share-based payments be recognized in the company's financial statements. FAS 123(R) was implemented by the company in the first quarter of 2006. The company previously accounted for these payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. For a more detailed discussion of the implementation for FAS 123(R) see Note 1 - Basis of Preparation and Presentation.

In September 2005, the Emerging Issues Task Force issued Issue No. 04-13 (EITF 04-13), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The EITF concluded that inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 is effective in reporting periods beginning after March 15, 2006. We have not entered into the type of transactions covered under EITF 04-13, so we do not expect EITF 04-13 to have a material impact on our results of operations, financial condition or cash flows.

In June 2005, the FASB issued Financial Accounting Standards No. 154, “Accounting Changes and Error Corrections,” (FAS 154) which establishes new standards on accounting for changes in accounting principles. Under this new rule, all such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. FAS 154 completely replaces APB 20 and FAS 3, though it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. FAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after May 2005. The application of FAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of FAS 154. Implementation of this statement did not have a material impact on the company's results of operations, financial condition or cash flows.

In June 2005, the Emerging Issues Task Force issued EITF Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights (EITF 04-05). EITF 04-05 provides guidance in determining whether a general partner controls a limited partnership by determining the limited partners’ substantive ability to dissolve (liquidate) the limited partnership as well as assessing the substantive participating rights of the limited partners within the limited partnership. EITF 04-05 states that if the limited partners do not have substantive ability to dissolve (liquidate) or have substantive participating rights, then the general partner is presumed to control that partnership and would be required to consolidate the limited partnership. This EITF is effective in fiscal periods beginning after December 15, 2005. Implementation of this statement did not have a material impact on the company's results of operations, financial condition or cash flows.

In June 2006, 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 SFAS No. 109, "Accounting for Income Taxes". FIN 48 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 tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. The company is currently reviewing the effects of this interpretation and the company does not expect the implementation of this statement to have a material impact on the company's results of operations, financial condition or cash flows.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)". According to the provisions of EITF 06-3:

· taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

· that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies". In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

EITF 06-3 should be applied to financial reports for interim and annual reporting periods beginning after December 15, 2006. Because the provisions of EITF 06-3 require only the presentation of additional disclosures, we do not expect the adoption of EITF 06-3 to have an effect on the company's results of operations, financial condition or cash flows.

In September 2006, the FASB issued FAS No. 157, “Fair Value Measurements” (FAS No. 157). FAS No. 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 No. 157 is effective for fiscal years beginning after November 15, 2007. The company is currently assessing the impact of FAS No. 157 on its results of operations, financial condition and cash flows.

In September 2006, the SEC staff issued Staff Accounting Bulletin (SAB) Topic 1N, "Financial Statements - Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). The SEC staff is providing guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether the current year's financial statements are materially misstated and should be restated. SAB 108 is effective for fiscal years ending after November 18, 2006, and early application is encouraged. The company does not believe SAB 108 will have a material impact on its results of operations, financial condition and cash flows.

NOTE 7 - GOODWILL

Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company, CDC Drilling Company, SerDrilco Incorporated, Sauer Drilling Company and Strata Drilling, L.L.C. over the fair value of the net assets acquired. An impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to the company's drilling segment.

NOTE 8 - HEDGING ACTIVITY

The company periodically enters into derivative commodity instruments to hedge its exposure to the fluctuations in the prices it receives for its oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists.

In January 2005, the company entered into the following two natural gas collar contracts:

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.30

In March 2005, the company also entered into an oil collar contract:

Oil Collar Contract:

Production volume covered	1,000 Barrels/day
Period covered	April through December of 2005
Prices	Floor of $45.00 and a ceiling of $69.25

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the September 30, 2005 balance sheet as a derivative liability of $2.9 million and at a loss of $1.8 million, net of tax, in accumulated other comprehensive income. The natural gas collar contracts decreased natural gas revenues by $1.2 million during the third quarter and first nine months of 2005.

In February 2005, the company entered into an interest rate swap to help manage its 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. This period coincides with the remaining length of the company's current credit facility. 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 2006 the company's interest expense was decreased by $0.2 million and $0.4 million, respectively. The company's interest expense was increased by $0.1 million in the third quarter of 2005 and $0.2 million for the nine months ended September 30, 2005. The fair value of the swap was recognized on the September 30, 2006 balance sheet as current and non-current derivative assets totaling $0.8 million and a gain of $0.5 million, net of tax, in accumulated other comprehensive income.

NOTE 9 - INDUSTRY SEGMENT INFORMATION

The company has three business segments:

- Contract Drilling,
- Oil and Natural Gas Exploration and Production and
- Gas Gathering and Processing

These three segments represent the company's 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 Exploration and Production segment is engaged in the acquisition, development and production of oil and natural gas properties and the Gas Gathering and Processing segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

The company evaluates the performance of these operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. The company has natural gas production in Canada, which is not significant. Information regarding the company's operations by segment for the three and nine month periods ended September 30, 2006 and 2005 is as follows:

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In thousands)			
Revenues:				
Contract drilling	$ 196,953	$ 127,119	$ 550,428	$ 336,537
Elimination of inter-segment revenue	14,492	7,246	30,629	14,158
Contract drilling net of inter-segment revenue	182,461	119,873	519,799	322,379
Oil and natural gas	91,238	83,979	267,518	202,819
Gas gathering and processing	29,045	28,720	83,303	71,846
Elimination of inter-segment revenue	3,407	2,159	10,463	5,951
Gas gathering and processing net of inter-segment revenue	25,638	26,561	72,840	65,895
Other (1)	557	635	2,894	1,402
Total revenues	$ 299,894	$ 231,048	$ 863,051	$ 592,495
Operating Income (2):				
Contract drilling	$ 90,463	$ 41,693	$ 243,689	$ 96,479
Oil and natural gas	42,121	51,711	131,884	116,271
Gas gathering and processing	1,785	1,264	5,087	3,012
Total operating income	134,369	94,668	380,660	215,762
General and administrative expense	(4,630)	(3,324)	(12,998)	(10,455)
Interest expense	(1,228)	(885)	(3,235)	(2,157)
Other income	557	635	2,894	1,402
Income before income Taxes	$ 129,068	$ 91,094	$ 367,321	$ 204,552

(1) Includes a $1.0 million gain 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.

NOTE 10 - SUBSEQUENT EVENTS

On October 13, 2006, the company's wholly owned subsidiary, Unit Petroleum Company, completed the acquisition of Brighton Energy, LLC, (Brighton) a privately owned oil and natural gas company for approximately $67.0 million. This acquisition involved all of Brighton’s oil and natural gas assets in the Arkoma Basin excluding Atoka and Coal counties in Oklahoma and included approximately 27.0 Bcfe of proved oil and natural gas 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 will be included in the company's results of operations starting in October 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying consolidated condensed balance sheet of Unit Corporation and its subsidiaries as of September 30, 2006, and the related consolidated condensed statements of income and comprehensive income for each of the three and nine month periods ended September 30, 2006 and 2005 and the consolidated condensed statements of cash flows for the nine month periods ended September 30, 2006 and 2005. 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 consolidated condensed 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, 2005, and the related consolidated statements of income, shareholders’ equity and of cash flows for the year then ended (not presented herein), management’s assessment of the effectiveness of the company’s internal control over financial reporting as of December 31, 2005 and the effectiveness of the company’s internal control over financial reporting as of December 31, 2005; and in our report dated March 13, 2006, we expressed unqualified opinions thereon. The consolidated financial statements and management’s assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated condensed balance sheet as of December 31, 2005, 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 2, 2006

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

This quarterly report on Form 10-Q is for the three and nine months ended September 30, 2006. This quarterly report modifies and supersedes documents filed before this quarterly report. The SEC allows us to "incorporate by reference" information that we file with them, which means that we can disclose important information to you by referring you directly to those documents. Information incorporated by reference is considered to be part of this quarterly report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained in this quarterly report.

You should carefully review the information contained in this quarterly report and particularly consider any risk factors that we set forth in this quarterly report and in other reports or documents that we file from time to time with the SEC. In this quarterly report, we state our beliefs of future events and of our future financial performance. In some cases, you can identify these so-called "forward-looking statements" by words such as "may," "will," "should," "expects," "pla "anticipates," "believes," "estimates," "predicts," "potential," or "continue," or the negative of those words, and other compara words. You should be aware that those statements are only our predictions. In evaluating those statements, you should specifically consider various factors, including the risks outlined below. Actual events or our actual results may differ materially from any of our forward-looking statements. Except as required by law, we disclaim any obligation to update forward looking statements to reflect events or circumstances after the date of this report.

You should read the following Management's Discussion and Analysis of Financial Condition and Results of Operations in conjunction with the unaudited condensed consolidated financial statements and the related notes that appear elsewhere in this report

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 credit facility.

Our three principal business segments are:

- contract drilling carried out by our subsidiary Unit Drilling Company and its subsidiaries;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company; and
- natural gas buying, selling, gathering and processing carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries.

Our cash flow is influenced mainly by:

- the prices and demand 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.

The following is a summary of certain financial information as of September 30, 2006 and 2005 and for the nine months ended September 30, 2006 and 2005:

	September 30, 2006	September 30, 2005	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 96,760	$ 56,998	70%
Long-Term Debt	$ 145,100	$ 115,600	26%
Shareholders' Equity	$ 1,074,561	$ 749,802	43%
Ratio of Long-Term Debt to Total Capitalization	12%	13%	(8)%
Net Income	$ 230,995	$ 127,982	80%
Net Cash Provided by Operating Activities	$ 349,599	$ 189,852	84%
Net Cash Used in Investing Activities	$ (347,508)	$ (222,012)	57%
Net Cash Provided by (Used in) Financing Activities	$ (2,432)	$ 32,223	(108)%

The following table summarizes certain operating information for the nine months ended September 30, 2006 and 2005:

	September 30, 2006	September 30, 2005	Percent Change
Oil Production (MBbls)	1,062	788	35%
Natural Gas Production (MMcf)	32,350	24,055	34%
Average Oil Price Received	$ 57.18	$ 48.16	19%
Average Natural Gas Price Received	$ 6.28	$ 6.74	(7)%
Average Natural Gas Price Received Excluding Hedges	$ 6.28	$ 6.79	(8)%
Average Number of Our Drilling Rigs in Use During the Period	109.8	100.7	9%
Total Number of Drilling Rigs Available at the End of the Period	116	110	5%
Average Dayrate	$ 18,442	$ 11,583	59%
Gas Gathered—MMBtu/day	245,435	129,754	89%
Gas Processed—MMBtu/day	27,226	32,709	(17)%
Number of Active Natural Gas Gathering Systems	37	35	6%

At September 30, 2006, we had unrestricted cash totaling $0.6 million and we had borrowed $145.1 million of the $200.0 million we had then elected to have available under our credit facility.

Our Credit Facility. At September 30, 2006, we had a $235.0 million revolving credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and effective September 15, 2006, the company elected to increase the commitment amount available from $175.0 million to $200.0 million. We are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We incurred origination, agency and syndication fees of $515,000 at the inception of the credit facility. During 2005, we incurred additional origination, agency and syndication fees of $187,500 while amending the credit facility and these fees are being amortized over the remaining life of the credit facility. The average interest rate for the first nine months of 2006 was 5.8% including effect of the interest rate swap. At September 30, 2006 and October 30, 2006, our borrowings were $145.1 million and $170.6 million, respectively.

Effective October 10, 2006, we entered into a Third Amendment to our existing credit facility. In general, this amendment modified the existing credit facility agreement by amending each of the Bank's Aggregate Commitment and the Maximum Credit Amount (each as defined in the credit facility agreement) from $235 million to the maximum principal amount $275 million. A facility fee of $60,000 was incurred with the signing of this amendment. This fee will be amortized over the remaining term of the loan.

The borrowing base under the current credit facility is subject to re-determination on May 10 and November 10 of each year. The latest redetermination supported the full $275.0 million. Each re-determination is based primarily on a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. The determination of our borrowing base also includes an amount representing a small part of the value of our drilling rig fleet (limited to $20 million) as well as such loan value as the banks reasonably attribute to Superior Pipeline Company's cash flow as defined in the facility agreement. The credit facility agreement allows for one requested special re-determination of the borrowing base by either the banks or us between each regularly scheduled re-determination date.

At our election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which such LIBOR Rate option applies may be repaid on three days prior notice and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR Rate is computed at the LIBOR Base Rate applicable for the interest period plus 1.00% to 1.50% depending on the level of debt as a percentage of the total loan value and payable at the end of each term or every 90 days whichever is less. Borrowings not under the LIBOR Rate bear interest at the JPMorgan Chase 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, 2006, all of the $145.1 million we had borrowed was subject to the LIBOR rate.

The credit facility agreement 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 banks.

The credit agreement also requires us to have at the end of each quarter:

. consolidated net worth of at least $350 million,
. a current ratio (as defined in the credit agreement) of not less than 1 to 1, and
. a leverage ratio of long-term debt to consolidated EBITDA (as defined in the loan agreement)for themost recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On September 30, 2006, we were in compliance with these 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. This period coincides with the remaining length of our current credit agreement. 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 $0.4 million in the first nine months of 2006. The fair value of the swap was recognized on the September 30, 2006 balance sheet as current and non-current derivative assets totaling $0.8 million and a gain of $0.5 million, net of tax, in accumulated other comprehensive income.

Contractual Commitments. At September 30, 2006 we have 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)	$ 155,893	$ 8,089	$ 147,804	$ **---**	$ ---
Retirement Agreements (2)	1,484	694	790	**---**	---
Operating Leases (3)	3,840	1,236	2,220	384	---
Drill Pipe, Drilling Rigs and Equipment Purchases (4)	9,307	9,307	---	---	---
Total Contractual Obligations	$ 170,524	$ 19,326	$ 150,814	$ 384	$ ---

(1) See the previous discussion in Management Discussion and Analysis regarding bank debt. This obligation is presented in accordance with the terms of the credit facility agreement and includes interest calculated at the September 30, 2006 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, will be paid in monthly payments of $25,000 starting in July 2003 and continuing 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 will be paid in quarterly payments 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, will be paid in monthly payments of $31,250 starting in November 2006 and continuing through October 2008. These liabilities as presented above are undiscounted.
(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston, Midland, and Weatherford, Texas; Pinedale, Wyoming and Denver, Colorado under the terms of operating leases expiring through January 31, 2010. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess rig equipment and production inventory.
(4) We have committed to purchase approximately $1.8 million of drill collars and kellys and we have also committed to purchase $1.7 million of additional rig components. In April 2006, we committed $6.0 million for the purchase of major components to construct two drilling rigs with $1.2 million or 20% paid at the time of commitment. The remaining $4.8 million will be paid at delivery. These rigs should be placed into service in the first quarter of 2007. We have committed to purchase approximately 50 vehicles within the next 9 months for $1.0 million.

On December 8, 2003, the company acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest, L.L.C., for $35.0 million in cash. The terms of that acquisition include an earn-out provision allowing the sellers to receive one-half of the cash flow in excess of $10.0 million for each of the three years following the acquisition. For the year ending December 31, 2006, the third year of the earn-out period, the drilling rigs included in the earn-out provision had cash flow during the first nine months of $35.0 million.

At September 30, 2006, 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)	$ 2,547	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement (2)	$ 2,983	$ 289	Unknown	Unknown	Unknown
Plugging Liability (3)	$ 31,846	$ 643	$ 2,113	$ 2,323	$ 26,767
Gas Balancing					

Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$ 21,590	$ 6,194	$ 6,255	$ 1,468	$ 7,673

(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 consolidated condensed 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. In January 2006, the compensation committee elected to allow 33 employees to participate in the plan.

(3) On January 1, 2003 we adopted Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations”(FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled or acquired).

(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 2006, with a subsidiary of ours serving as general partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most of our exploration operations and most producing property acquisitions 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.

(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. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow.

In January 2005, the we entered into the following two natural gas collar contracts:

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.30

In March 2005, the we also entered into an oil collar contract:

Oil Collar Contract:

Production volume covered	1,000 Barrels/day

Period covered	April through December of 2005
Prices	Floor of $45.00 and a ceiling of $69.25

All of these hedges are cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the September 30, 2005 balance sheet as a derivative liability of $2.9 million and at a loss of $1.8 million, net of tax, in accumulated other comprehensive income. The natural gas collar contracts decreased natural gas revenues by $1.2 million during the third quarter and first nine months of 2005.

We did not have any oil and natural gas hedges outstanding at September 30, 2006.

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. This period coincides with the remaining length of our current credit facility. 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, 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. In the third quarter and first nine months of 2005, our interest expense was increased by $0.1 million and $0.2 million, respectively, as a result of the interest rate swap. The fair value of the swap was recognized on the September 30, 2006 balance sheet as current and non-current derivative assets totaling $0.8 million and a gain of $0.5 million, net of tax, in accumulated other comprehensive income.

Self-Insurance or Retentions. We are self-insured for certain costs and 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 $0.5 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. We have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas 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 2006 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $337,000 per month ($4.0 million annualized) change in our pre-tax operating cash flow. Our nine month 2006 average natural gas price was $6.28 compared to an average natural gas price of $6.74 for the first nine months of 2005. A $1.00 per barrel change in our oil price would have an $110,000 per month ($1.3 million annualized) change in our pre-tax operating cash flow based on our production in the first nine months of 2006. Our first nine month 2006 average oil price was $57.18 compared with an average oil price of $48.16 received in the first nine months of 2005.

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 agreement 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.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of our oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. Full cost companies are required to use the unescalated prices in effect as of the end of each fiscal quarter to calculate the discounted future revenues. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs, even if prices are depressed for only a short period of time. Under the SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

In the third quarter of 2006, natural gas prices declined significantly. The unescalated prices used to calculate our reserves at September 30, 2006 for purposes of the ceiling test were $3.86 per Mcf for natural gas, $62.91 per Bbl for oil and $39.53 per Bbl for natural gas liquids. As a result, the ceiling test as of September 30, 2006 indicated an impairment of the oil and natural gas properties of approximately $20.9 million, net of income taxes. However, natural gas prices subsequent to September 30, 2006, have improved sufficiently to eliminate this calculated impairment. As a result, the company is not required to record a write-down of its oil and natural gas properties under the full cost method of accounting in the third quarter. Since oil and natural gas prices remain volatile, we may be required to write down the carrying value of our oil and natural gas properties at the end of future reporting periods. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

Most of our natural gas production is sold to third parties under month-to-month contracts. Presently we believe that our buyers will be able to perform their commitments to us.

***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 drilled 178 wells (62.27 net wells) in the first nine months of 2006 compared to 135 wells (50.25 net wells) in the first nine months of 2005. Our total capital expenditures for oil and natural gas exploration and acquisitions excluding the increases in provision for plugging liability in the first nine months of 2006 totaled $200.0 million. Based on current prices, we plan to drill an estimated 235 wells in 2006 and estimate our total capital expenditures for oil and natural gas exploration and acquisitions to be approximately $240.0 million excluding the $32.4 million paid in the acquisition of certain oil and natural gas properties from a group of private entities in the second quarter of 2006 and $67.0 million we paid for the acquisition of Brighton Energy, LLC in October 2006. Whether we are able to drill the full number of wells we are planning on drilling is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, the cost to drill wells, the weather and the efforts of outside industry partners.

On June 15, 2005, we completed the acquisition of certain oil and natural gas properties from a private company for an adjusted purchase price of $23.1 million in cash. The acquisition consisted of approximately 14.0 Bcfe of proved oil and natural gas reserves and several probable locations. The properties are located in Oklahoma and produced 2.5 MMcfe per day at the time of acquisition. The effective date of this acquisition was April 1, 2005. The results of operations for these acquired properties are included in the statement of income beginning June 1, 2005 with the results for the period from April 1, 2005 through May 31, 2005 included as part of the adjusted purchase price.

On November 16, 2005, we completed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $82.0 million in cash. The acquisition consisted of approximately 42.5 Bcfe of proved oil and natural gas reserves. The properties are located in Oklahoma, Arkansas and Texas and at the time of the acquisition produced 6.5 MMcfe per day. The effective date of this acquisition was July 1, 2005. The results of operations for the acquired properties are included in the statement of income beginning November 1, 2005, with the results for the period from July 1, 2005 through October 31, 2005 included as part of the adjusted purchase price.

On May 16, 2006, our wholly owned subsidiary, Unit Petroleum Company, announced it had 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 are included in the statement of income beginning May 1, 2006.

On October 13, 2006, our wholly owned subsidiary, Unit Petroleum Company, completed the acquisition of Brighton Energy, LLC, a privately owned oil and natural gas company for approximately $67.0 million in cash. The acquisition involves all of Brighton’s oil and natural gas assets in the Arkoma Basin excluding Atoka and Coal counties in Oklahoma and includes approximately 27.0 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 has an effective date of August 1, 2006 and will be included in the company's results of operations starting in October 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.

Because of the current high demand for drilling rigs we are experiencing some difficulty in hiring and retaining all of the rig crews we need. In response to our labor difficulties, we implemented longevity pay incentives in 2004 and increased wages in some of our drilling areas that had not already received pay increases in 2004 and at the end of the second quarter of 2005. We also increased wages in one of our divisions starting in the second quarter of 2006 and again, at the end of the second quarter for all but two of our divisions. To date, these efforts have allowed us to meet our labor requirements. However, if current demand for drilling rigs continues, shortages of experienced personnel may limit our ability to operate our drilling rigs at or above the 97% utilization rate we achieved in the first nine months of 2006.

We currently do not have any shortages of drill pipe and drilling equipment. At September 30, 2006 we have commitments to purchase approximately $1.8 million of drill collars and kellys in 2006 and we have also committed to purchase $1.7 million of additional rig components. We are also constructing another drilling rig which should be placed in service in the fourth quarter of 2006.

In April 2006, we committed to purchase major components to construct two drilling rigs for a total of $6.0 million. These rigs should be placed into service in the first quarter of 2007. We paid $1.2 million or 20% at the time of the commitment and will pay the remainder at delivery.

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 2006, our average dayrate for the 116 drilling rigs that we owned was $19,592 with a 97% utilization rate. In the first nine months of 2006 our average dayrate was $18,442 per day compared to $11,583 in the first nine months of 2005. The average number of drilling rigs used was 109.8 (97%) in the first nine months of 2006 compared to 100.7 (98%) in the first nine months of 2005. Based on the average utilization of our drilling rigs during the first nine months of 2006, a $100 per day change in dayrates has a $10,980 per day ($4.0 million annualized) change in our pre-tax operating cash flow. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas and the availability of drilling rigs to meet the demands of the industry.

In January 2006, one of our drilling rigs was destroyed by a fire. Drilling rig No. 31, a 600 horsepower drilling rig, one of our smaller drilling rigs, experienced a blow out during initial drilling operations at an approximate depth of 800 feet. 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. The proceeds however will not cover the replacement cost of a new rig to replace the one destroyed. .

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 2006 and 2005, we drilled 50 and 35 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $16.6 million and $5.6 million during the first nine months of 2006 and 2005, respectively, reduced the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

<u>Drilling Acquisitions and Capital Expenditures.</u> On January 5, 2005, we acquired a subsidiary of Strata Drilling, L.L.C. for $10.5 million in cash. In this acquisition, we acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two drilling rigs are 1,500 horsepower, diesel electric rigs with the capacity to drill 12,000 to 20,000 feet. After refurbishments costing $1.0 million and $5.2 million, respectively, the first drilling rig was placed in service in January 2005 and the second drilling rig was placed in service in August of 2005. Both of these rigs are in our Rocky Mountain Division. The results of operations for this acquired company are included in the statement of income for the period after January 5, 2005.

On August 31, 2005, we completed our acquisition of all the Texas drilling operations of Texas Wyoming Drilling, Inc., a Texas-based privately-owned company, with the exception of one rig which the company subsequently obtained on October 13, 2005. The purchase price for this acquisition was $31.6 million. Of that amount, $13.3 million was paid in cash and $12 million issued in stock, representing 246,053 shares, on August 31, 2005. The remaining $6.3 million was paid in cash on October 13, 2005. Six of the seven rigs are active in the Barnett Shale area of North Texas. Six of the seven drilling rigs are mechanical, with one being a diesel electric rig. They range from 400 to 1,700 horsepower. The results of operations for the first six drilling rigs are included in the statement of income for the period after August 31, 2005 and the results of operations for the seventh rig acquired is included in the statement of income for the period after October 12, 2005.

In January 2005, we completed the construction of a 1,500 horsepower diesel electric drilling rig which began operating in the Anadarko Basin. The drilling rig was constructed for approximately $2.5 million with the majority of the expenditures occurring in 2004. In May 2005, we completed the construction of a 1,500 horsepower diesel electric drilling rig which began operating in the Rocky Mountain Division. This drilling rig was constructed for $8.0 million with $1.8 million of the parts acquired in the Strata acquisition. In December 2005, we completed the construction of a 1,000 horsepower diesel electric drilling rig which began operating in the Anadarko Basin. The drilling rig was constructed for approximately $3.2 million.

In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired 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 we began moving a rig to our Rocky Mountain Division which we completed construction of during the first quarter of 2006. In the second quarter of 2006, we also completed the purchase of two new drilling rigs for $15.2 million with $4.6 million paid prior to second quarter of 2006 and the remaining $10.6 million paid at delivery. 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 rig which was moved into our Rocky Mountain Division. The addition of this rig brings our rig fleet to 116 at the end of September 2006.

We began constructing another drilling rig which should be placed in service in the fourth quarter of 2006. In April 2006, we committed to purchase major components to construct two drilling rigs for $6.0 million. We paid $1.2 million or 20% at the time of the commitment and will pay the remainder at delivery. The rigs should be placed in service in the first quarter of 2007.

For our contract drilling operations, during the first nine months of 2006, we incurred $128.6 million in capital expenditures. For the year 2006, we have budgeted capital expenditures of approximately $199.0 million which includes the eight rigs previously discussed. We have plans to build two additional rigs, but due to delays with the manufacturer these rigs will not be available for service until the first quarter of 2007.

Acquisition of Natural Gas Gathering and Processing Company. Our natural gas gathering and processing operations are conducted through Superior Pipeline Company, L.L.C. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and it operates three natural gas treatment plants, owns seven processing plants, 37 active gathering systems and 600 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 our natural gas and third party natural gas and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During the first nine months of 2006, Superior purchased $6.4 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.0 million. Intercompany revenue from services and purchases of production between this business segments and our oil and natural gas operations has been eliminated in our consolidated condensed financial statements.

In September 2006, our natural gas gathering and processing operations closed the acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal assets of the acquired company consist of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. The purchase had an effective date of July 31, 2006. The financial results of the acquisition are included in the company's results of operations 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. As part of the acquisition, the company acquired long-term contracts for the gathering and processing of natural gas that will flow through this gathering system.

During the first nine months of 2006 we incurred $38.3 million in capital expenditures for our natural gas gathering and processing segment including acquisitions as compared to $17.8 million in the first nine months of 2005. For all of 2006, we have budgeted capital expenditures of approximately $29.0 million excluding the Berkshire Energy LLC acquisition. Our focus is on growing this segment through the construction of new facilities or acquisitions.

Superior gathered 245,435 MMBtu per day in the first nine months of 2006 compared to 129,754 MMBtu per day in the first nine months of 2005 and processed 27,226 MMBtu per day in the first nine months of 2006 compared to 32,709 MMBtu per day in the first nine months of 2005. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 142,512 MMBtu and 58,332 MMBtu per day during the first nine months of 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet is accepting the delivered natural gas unprocessed causing a reduction in processed natural gas between the quarters.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 11 oil and natural gas limited partnerships which were formed privately and publicly. 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. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by management to be reasonable. During 2005, the total paid to us for all of these fees was $1.0 million and during the first nine months of 2006 the amount paid was $0.9 million. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated condensed financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

Before January 1, 2006, we accounted for our stock-based compensation plans under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the 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. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. 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, will be recognized in our 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, such 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 our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. As a result of the implementation of FAS 123(R) we expensed $0.6 million in the contract drilling segment, $0.4 million in the oil and natural gas segment and $1.2 million to corporate general and administrative expense, for a total of $2.2 million, in the first nine months of 2006 and capitalized as part of geological and geophysical cost of $0.6 million.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, upon adoption of FAS 123(R) we eliminated $2.2 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our condensed consolidated balance sheet.

The remaining unrecognized compensation cost related to unvested awards at September 30, 2006 is approximately $2.6 million with $0.7 million of that amount to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years. If we had applied the fair value provisions of FAS 123(R) to stock-based employee compensation for the nine month period ended September 30, 2005, net income and earnings per share would have been reduced by approximately $1.5 million and $0.03 respectively and for the three month period ended September 30, 2005 by approximately $0.6 million and $0.01, respectively.

Under the provision of FAS 123(R), tax deductions associated with our stock based compensation plans in excess of the compensation cost recognized are recorded as an increase to additional paid in capital and reflected as a financing cash flow in the statement of cash flows. In the first nine months of 2006, almost all options exercised were incentive stock options for which no tax deduction was immediately available. Accordingly, the adoption of FAS 123(R) did not have a material impact on our consolidated statements of cash flows for the nine month period ended September 30, 2006.

In September 2005, the Emerging Issues Task Force issued Issue No. 04-13 (EITF 04-13), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The EITF concluded that inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 was effective in reporting periods beginning after March 15, 2006. We have not entered into the type of transactions covered under EITF 04-13, so we do not expect EITF 04-13 to have a material impact on our results of operations, financial condition or cash flows.

In June 2005, the FASB issued Financial Accounting Standards No. 154, “Accounting Changes and Error Corrections,” which establishes new standards on accounting for changes in accounting principles. Under this new rule, all such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. FAS 154 completely replaces APB 20 and FAS 3, though it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. FAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after May 2005. The application of FAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of FAS 154. Implementation of this statement did not have a material impact on our results of operations, financial condition or cash flows.

In June 2005, the Emerging Issues Task Force issued EITF Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights ("EITF 04-05"). EITF 04-05 provides guidance in determining whether a general partner controls a limited partnership by determining the limited partners' substantive ability to dissolve (liquidate) the limited partnership as well as assessing the substantive participating rights of the limited partners within the limited partnership. EITF 04-05 states that if the limited partners do not have substantive ability to dissolve (liquidate) or have substantive participating rights, then the general partner is presumed to control that partnership and would be required to consolidate the limited partnership. This EITF is effective in fiscal periods beginning after December 15, 2005. Implementation of this statement did not have a material impact on our results of operations, financial condition or cash flows.

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 SFAS No. 109, "Accounting for Income Taxes". FIN 48 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 tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We are currently reviewing the effects of this interpretation and we do not expect the implementation of this statement to have a material impact on our results of operations, financial condition or cash flows.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)". According to the provisions of EITF 06-3:

· taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

· that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies". In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

EITF 06-3 should be applied to financial reports for interim and annual reporting periods beginning after December 15, 2006. Because the provisions of EITF 06-3 require only the presentation of additional disclosures, we do not expect the adoption of EITF 06-3 to have an effect on our results of operations, financial condition or cash flows.

In September 2006, the FASB issued FAS No. 157, "Fair Value Measurements" (FAS No. 157). FAS No. 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 No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of FAS No. 157 on our results of operations, financial condition and cash flows.

In September 2006, the SEC staff issued Staff Accounting Bulletin (SAB) Topic 1N, "Financial Statements - Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). The SEC staff is providing guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether the current year's financial statements are materially misstated and should be restated. SAB 108 is effective for fiscal years ending after November 18, 2006, and early application is encouraged. The company does not believe SAB 108 will have a material impact on its results of operations, financial condition and cash flows.

RESULTS OF OPERATIONS

Quarter Ended September 30, 2006 versus Quarter Ended September 30, 2005

Provided below is a comparison of selected operating and financial data for the third quarter of 2006 versus the third quarter of 2005:

		Quarter Ended September 30, 2006		Quarter Ended September 30, 2005	Percent Change
Total Revenue	$	299,894,000	$	231,048,000	30%
Net Income	$	81,265,000	$	57,638,000	41%
Drilling:					
Revenue	$	182,461,000	$	119,873,000	52%
Operating costs	$	78,595,000	$	67,161,000	17%
Percentage of revenue from daywork contracts		100%		100%	
Average number of rigs in use		110.6		102.6	8%
Average dayrate on daywork contracts	$	19,559	$	13,117	49%
Depreciation	$	13,403,000	$	11,019,000	22%
Oil and Natural Gas:					
Revenue	$	91,238,000	$	83,979,000	9%
Operating costs	$	21,560,000	$	15,913,000	35%
Average natural gas price (Mcf)	$	6.02	$	8.13	(26)%
Average oil price (Bbl)	$	59.55	$	54.60	9%
Natural gas production (Mcf)		11,200,000		8,542,000	31%
Oil production (Bbl)		376,000		251,000	50%
Depreciation, depletion and amortization rate (Mcfe)	$	2.04	$	1.62	26%
Depreciation, depletion and amortization	$	27,557,000	$	16,355,000	68%
Gas Gathering and Processing:					
Revenue	$	25,638,000	$	26,561,000	(3)%
Operating costs	$	22,216,000	$	24,395,000	(9)%
Depreciation and amortization	$	1,637,000	$	902,000	81%
Gas gathered - MMbtu/day		276,888		159,821	73%
Gas processed - MMbtu/day		35,124		36,061	(3)%
General and Administrative Expense	$	4,630,000	$	3,324,000	39%
Interest Expense	$	1,228,000	$	885,000	39%
Income Tax Expense	$	47,803,000	$	33,456,000	43%
Average Interest Rate		6.04%		4.89%	24%
Average Long-Term Debt Outstanding	$	131,948,000	$	104,817,000	26%

Industry demand for our drilling rigs increased throughout 2005 and remained strong in the first nine months of 2006. Drilling revenues increased $62.6 million or 52% in the third quarter of 2006 versus the third quarter of 2005. Since the second quarter of 2005, we have placed 14 additional drilling rigs into service. Six of the drilling rigs were newly constructed drilling rigs, one was a refurbished rig acquired in the first quarter on 2005 and seven were drilling rigs acquired in the acquisition of Texas Wyoming Drilling, Inc. We lost one of our older drilling rigs to a blow out and subsequent fire early in the first quarter of 2006. The net 13 additional drilling rigs increased our third quarter 2006 drilling revenues by approximately 14%. The increase in revenue from these additional drilling rigs and the increase in utilization of our previously owned drilling rigs represented 15% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 85% of the increase in total drilling revenues. Our average dayrate in the third quarter of 2006 was 49% higher than in the third quarter of 2005. Demand for our drilling rigs is anticipated to be strong through the remainder of 2006 and into 2007, but we do not expect the dramatic increases in daywork revenue per day as was experienced throughout 2005 and into the third quarter of 2006. Opportunities to increase rig revenues through economical acquisition of existing drilling rigs is expected to be limited in 2006 and into 2007, due to the high demand for drilling rigs and the resulting effect of increased rig costs.

Drilling operating costs increased $11.4 million or 17% between the comparative quarters. The increase in operating costs from the net 13 additional drilling rigs placed in service since the first quarter of 2005 and increased utilization of our previously owned drilling rigs represented 67% of the total increase in operating cost. Increases in operating cost per day accounted for 33% of the increase in total operating costs. Operating cost per day increased $375 in the third quarter of 2006 when compared with the third quarter of 2005. The majority of the increase was attributable to costs directly associated with increases in labor cost. We expect the demand for drilling rigs to remain high during the remainder of 2006 and into 2007, resulting in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in third quarter of 2006 and we drilled one footage well in the third quarter of 2005. Contract drilling depreciation increased $2.4 million or 22%. The addition of the net 13 drilling rigs placed in service since the second quarter of 2005 increased depreciation $1.1 million or 10% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

Oil and natural gas revenues increased $7.3 million or 9% in the third quarter of 2006 as compared to the third quarter of 2005. A 34% increase in equivalent production volumes, and an increase in average oil prices primarily accounted for the increase which was partially offset by decreased natural gas prices. Average oil prices between the comparative quarters increased 9% to $59.55 per barrel while natural gas prices declined 26% to $6.02 per Mcf. In the third quarter of 2006, natural gas production increased by 31% while oil production increased 50%. Increased oil and natural gas production came primarily from our ongoing development drilling activity, from two acquisitions completed in 2005 and from an acquisition completed in the second quarter of 2006. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2006 compared to 2005 will increase approximately 30%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $5.6 million or 35% in the third quarter of 2006 as compared to 2005. An increase in the average cost per equivalent Mcf produced represented 16% of the increase in production costs with the remaining 84% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 79% of the increase, gross production taxes 10%, general and administrative cost directly related to oil and natural gas production 8% and increased accretion on plugging liability 3%. Lease operating expenses per Mcfe increased 21% between the comparative quarters. The increase is primarily due to increases in the cost of goods and services. Total workover expense between the comparative quarters increased 4%. Gross production taxes increased due to the increase in natural gas volumes produced between the comparative quarters. General and administrative expenses increased as labor costs increased primarily due to a 16% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization (“DD&A”) increased $11.2 million or 68%. Higher production volumes accounted for 49% of the increase while increases in our DD&A rate represented 51% of the increase. The increase in our DD&A rate in the third quarter of 2006 compared to the third quarter of 2005 resulted primarily from a 14% increase in our finding cost in 2005 and continued increases in our finding cost into the first nine months of 2006. Demand for drilling rigs throughout our areas of exploration have increased the dayrates we pay to drill wells in our developmental program and the increase in natural gas and oil prices has caused increased sales prices for producing property acquisitions. We do believe there continues to be economical opportunities for acquisitions.

Our natural gas gathering and processing segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate three natural gas treatment plants and own seven processing plants, 37 active gathering systems and 600 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 natural gas gathering and processing revenues were $0.9 million lower in the third quarter of 2006 versus 2005 due to decreases in natural gas prices. Gas gathering volumes per day were 73% higher in the third quarter of 2006 as compared to the third quarter of 2005 while gas processing volumes per day were down 3% in the third quarter of 2006 as compared to the third quarter of 2005. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 153,883 MMBtu and 86,736 MMBtu per day during the third quarter of 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet is accepting the delivered natural gas unprocessed, causing a reduction in processed natural gas between the quarters. Our focus is on growing this segment through the construction of new facilities or acquisitions. Continued growth in this segment enhances our ability to gather and market our natural gas and third party natural gas and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities.

General and administrative expense increased $1.3 million or 39% in the third quarter of 2006 compared to the third quarter of 2005. The increase was primarily from increases in the number of employees and the additional expense incurred from the implementation of Financial Accounting Standards (FAS) No. 123(R) “Share-Based Payment" which requires the recognition of expense related to the value of stock options granted over their vesting period.

Total interest expense increased 39% between the comparative quarters. Average debt outstanding was 26% higher in the third quarter of 2006 as compared to the third quarter of 2005 primarily due to the fourth quarter 2005 and second quarter 2006 acquisition of producing properties for $82.0 million and $32.4 million in cash, respectively and the acquisition of a natural gas gathering system in the third quarter of 2006 for $21.7 million. Average debt outstanding accounted for approximately 47% of the interest expense increase, with the remaining 53% resulting from an increase in average interest rates on our bank debt. A reduction in interest expense of $0.2 million from the settlement of the interest rate swap partially offset the increases. 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 $0.9 million of interest in the third quarter of 2006 compared with $0.6 million in the third quarter of 2005.

Income tax expense increased $14.3 million or 43% due primarily to the increase in income before income taxes. Our effective tax rate for the third quarter of 2006 was 37.0% versus 36.7% in the third quarter of 2005. With our increase in income and the reduction of a majority of our net operating loss carryforwards in prior periods, the portion of our taxes reflected as current income tax expense has increased in the third quarter of 2006 when compared with the third quarter of 2005. Current income tax expense for the third quarter of 2006 and 2005 was $26.4 million and $19.6 million, respectively. Income taxes paid in the third quarter of 2006 were $28.2 million. During the second quarter of 2006, the state of Texas enacted a new margin tax which will go into effect in 2007. Based upon the nature of this margin tax, it will be accounted for as income tax in our financial statements. The impact on our deferred income tax liabilities and our effective tax rate for 2006 was not significant.

Nine Months Ended September 30, 2006 versus Nine Months Ended September 30, 2005

Provided below is a comparison of selected operating and financial data for the first nine months of 2006 versus the first nine months of 2005:

		Nine Months Ended September 30, 2006		Nine Months Ended September 30, 2005	Percent Change
Total Revenue	$	863,051,000	$	592,495,000	46%
Net Income	$	230,995,000	$	127,982,000	80%
Drilling:					
Revenue	$	519,799,000	$	322,379,000	61%
Operating costs	$	238,021,000	$	194,890,000	22%
Percentage of revenue from daywork contracts		100%		100%	
Average number of rigs in use		109.8		100.7	9%
Average dayrate on daywork contracts	$	18,442	$	11,583	59%
Depreciation	$	38,089,000	$	31,010,000	23%
Oil and Natural Gas:					
Revenue	$	267,518,000	$	202,819,000	32%
Operating costs	$	58,854,000	$	40,916,000	44%
Average natural gas price (Mcf)	$	6.28	$	6.74	(7)%
Average oil price (Bbl)	$	57.18	$	48.16	19%
Natural gas production (Mcf)		32,350,000		24,055,000	34%
Oil production (Bbl)		1,062,000		788,000	35%
Depreciation, depletion and amortization rate (Mcfe)	$	1.97	$	1.58	25%
Depreciation, depletion and amortization	$	76,780,000	$	45,632,000	68%
Gas Gathering and Processing:					
Revenue	$	72,840,000	$	65,895,000	11%
Operating costs	$	63,734,000	$	60,616,000	5%
Depreciation	$	4,019,000	$	2,267,000	77%
Gas gathered - MMbtu/day		245,435		129,754	89%
Gas processed - MMbtu/day		27,226		32,709	(17)%
General and Administrative Expense	$	12,998,000	$	10,455,000	24%
Interest Expense	$	3,235,000	$	2,157,000	50%
Income Tax Expense	$	136,326,000	$	76,570,000	78%
Average Interest Rate		5.76%		4.46%	29%
Average Long-Term Debt Outstanding	$	121,323,000	$	95,349,000	27%

Industry demand for our drilling rigs increased throughout 2005 and remained strong in the first nine months of 2006. Drilling revenues increased $197.4 million or 61% in the first nine months of 2006 versus the first nine months of

2005. Since the first quarter of 2005, we have placed 15 additional drilling rigs into service. Seven of the drilling rigs were newly constructed drilling rigs, one was a refurbished rig acquired in the first quarter on 2005 and seven were drilling rigs acquired in the acquisition of Texas Wyoming Drilling, Inc. We lost one of our older drilling rigs to a blow out and subsequent fire early in the first quarter of 2006. The net 14 additional drilling rigs increased our first nine months 2006 drilling revenues by approximately 15%. The increase in revenue from these additional drilling rigs and the increase in utilization of our previously owned drilling rigs represented 15% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 85% of the increase in total drilling revenues. Our average dayrate in the first nine months of 2006 was 59% higher than in the first nine months of 2005. Opportunities to increase rig revenues through economical acquisition of existing drilling rigs is expected to be limited during the remainder of 2006 and into 2007, due to the high demand for drilling rigs and the resulting effect of increased rig costs.

Drilling operating costs increased $43.1 million or 22% between the nine month periods. The increase in operating costs from the net 14 drilling rigs placed in service since the first quarter of 2005 and increased utilization of our previously owned drilling rigs represented 41% of the total increase in operating cost. Increases in operating cost per day accounted for 59% of the increase in total operating costs. Operating cost per day increased $850 in the first nine months of 2006 when compared with the first nine months of 2005. The majority of the increase was attributable to costs directly associated with increases in labor cost. We expect the demand for drilling rigs to remain high during the remainder of 2006 and into 2007, resulting in continued increases in our drilling rig expenses. We did not drill any turnkey or footage wells in first nine months of 2006 and we drilled one footage well in the first nine months of 2005. Contract drilling depreciation increased $7.1 million or 23%. The addition of the net 14 drilling rigs placed in service in 2005 increased depreciation $3.1 million or 10% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

Oil and natural gas revenues increased $64.7 million or 32% in the first nine months of 2006 as compared to the first nine months of 2005. The increase in oil and natural gas production volumes and an increase in oil prices accounted for the increase while decreased natural gas prices partially offset the increase. Average natural gas prices between the comparative nine month periods decreased 7% to $6.28 per Mcf while oil prices increased 19% to $57.18 per barrel. In the first nine months of 2006, natural gas production increased by 34% while oil production increased 35%. Increased oil and natural gas production came primarily from our ongoing development drilling activity, from two acquisitions completed in 2005 and from an acquisition completed in the second quarter of 2006. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2006 compared to 2005 will increase approximately 30%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $17.9 million or 44% in the first nine months of 2006 as compared to 2005. An increase in the average cost per equivalent Mcf produced represented 32% of the increase in production costs with the remaining 68% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 63% of the increase, gross production taxes 20%, general and administrative cost directly related to oil and natural gas production 12% and increased accretion on plugging liability 5%. Lease operating expenses per Mcfe increased 18% between the comparative nine month periods. The increase is primarily due to increases in the cost of goods and services. Gross production taxes increased due to the increase in oil and natural gas volumes produced and the increase in oil prices between the comparative nine month periods. General and administrative expenses increased as labor costs increased primarily due to a 15% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization ("DD&A") increased $31.1 million or 68%. Higher production volumes accounted for 51% of the increase while increases in our DD&A rate represented 49% of the increase. The increase in our DD&A rate in the first nine months of 2006 compared to the first nine months of 2005 resulted primarily from a 14% increase in our finding cost in 2005 and continued increases in our finding cost into the first nine months of 2006. Demand for drilling rigs throughout our areas of exploration have increased the dayrates we pay to drill wells in our developmental program and the increase in natural gas and oil prices has caused increased sales prices for producing property acquisitions. We do believe there continues to be economical opportunities for acquisitions.

Our natural gas gathering and processing revenues, operating expenses and depreciation were $6.9 million, $3.1 million and $1.8 million higher in the first nine months of 2006 versus 2005, respectively. Gas gathering volumes per day were 89% higher in the first nine months of 2006 as compared to the first nine months of 2005 while gas processing volumes per day were down 17% in the first nine months of 2006 as compared to the first nine months of 2005. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 142,512 MMBtu and 58,332 MMBtu per day during the first nine months of 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet is accepting the delivered natural gas unprocessed, causing a reduction in processed natural gas between the quarters. Our focus is on growing this segment through the construction of new facilities or acquisitions.

General and administrative expense increased $2.5 million in the first nine months of 2006 compared to the first nine months of 2005. The increase in cost was primarily attributable to increases in the number of employees and the additional expense incurred from the implementation of Financial Accounting Standards (FAS) No. 123(R) “Share-Based Payment" which requires the recognition of expense related to the value of stock options granted over their vesting period. In the first quarter of 2005, we recognized $0.7 million in personnel cost from the recognition of a liability associated with the retirement of Mr. Nikkel from his position as Chief Executive Officer.

Total interest expense increased 50% between the comparative nine month periods. Average debt outstanding was 27% higher in the first nine months of 2006 as compared to the nine months of 2005 primarily due to the fourth quarter 2005 and second quarter 2006 acquisition of producing properties for $82.0 million and $32.4 million in cash, respectively and the acquisition of a natural gas gathering system in the third quarter of 2006 for $21.7 million. Average debt outstanding accounted for approximately 58% of the interest expense increase, with the remaining 42% resulting from an increase in average interest rates on our bank debt. A reduction in interest expense of $0.4 million from the settlement of the interest rate swap partially offset the increases. 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 $2.5 million of interest in the first nine months of 2006 compared with $1.4 million in the first nine months of 2005.

Income tax expense increased $59.8 million or 78% due primarily to the increase in income before income taxes. Our effective tax rate for the first nine months of 2006 was 37.1% versus 37.4% in the first nine months of 2005. With our increase in income and the reduction of a majority of our net operating loss carryforwards in prior periods, the portion of our taxes reflected as current income tax expense has increased in the first nine months of 2006 when compared with the first nine months of 2005. Current income tax expense for the first nine months of 2006 and 2005 was $89.7 million and $41.2 million, respectively. Income taxes paid in the first nine months of 2006 were $103.5 million. During the second quarter of 2006, the state of Texas enacted a new margin tax which will go into effect in 2007. Based upon the nature of this margin tax, it will be accounted for as income tax in our financial statements. The impact on our deferred income tax liabilities and our effective tax rate for 2006 was not significant.

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;
- wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential:
- drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- business strategy;
- production of oil and natural gas reserves;
- growth potential for our gathering and processing operations;
- gathering systems and processing plants to be constructed or acquired;
- 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 2006 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $337,000 per month ($4.0 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have an $110,000 per month ($1.3 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. We did not have any oil or natural gas hedges outstanding at September 30, 2006.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the JPMorgan Chase 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. Historically, we have not used any financial instruments, such as interest rate swaps, to manage our exposure to possible increases in interest rates. However, 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. 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 2006, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $0.7 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 the company's disclosure controls and procedures are effective as of September 30, 2006 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 the company's internal controls over financial reporting during the quarter ended September 30, 2006 that could significantly affect these internal controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

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, 2005, 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, 2005.

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:

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.

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 2, 2006	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: November 2, 2006	By: /s/ David T. Merrill DAVID T. MERRILL Chief Financial Officer and Treasurer