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 March 31, 2005
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]

U N I T C O R P O R A T I O N
(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation or organization)	**(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 an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes _X_ No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common Stock, $.20 par value	**45,858,044**
Class	**Outstanding at May 2, 2005**

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

	March 31, 2005 (Unaudited)	December 31, 2004
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 470	$ 665
Restricted cash	77	2,571
Accounts receivable	103,628	93,180
Materials and supplies	14,132	13,054
Other	10,409	9,131
Total current assets	128,716	118,601
Property and Equipment:		
Drilling equipment	529,761	508,845
Oil and natural gas properties, on the full cost method:		
Proved properties	759,849	731,622
Undeveloped leasehold not being amortized	31,519	28,170
Gas gathering and processing equipment	40,996	38,417
Transportation equipment	13,621	13,559
Other	11,174	10,946
	1,386,920	1,331,559
Less accumulated depreciation, depletion, amortization and impairment	490,841	466,923
Net property and equipment	896,079	864,636
Goodwill	31,615	30,509
Other Assets	9,813	9,390
Total Assets	$ 1,066,223	$ 1,023,136

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS - CONTINUED

	March 31, 2005 (Unaudited)	December 31, 2004
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of other liabilities	$ 7,635	$ 5,837
Accounts payable	57,534	49,268
Accrued liabilities	21,149	19,818
Income taxes payable	9,342	33
Contract advances	1,075	2,220
Total current liabilities	96,735	77,176
Long-Term Debt	78,000	95,500
Other Long-Term Liabilities	37,555	37,725
Deferred Income Taxes	213,965	204,466
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	--	--
Common stock, $.20 par value, 75,000,000 shares authorized, 45,857,544 and 45,745,399 shares issued, respectively	9,172	9,149
Capital in excess of par value	312,514	310,132
Accumulated other comprehensive income (loss)	(1,436)	--
Retained earnings	319,718	288,988
Total shareholders' equity	639,968	608,269
Total Liabilities and Shareholders' Equity	$ 1,066,223	$ 1,023,136

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 March 31, 2005	Three Months Ended March 31, 2004
	(In thousands except per Share amounts)	
Revenues:		
Contract drilling	$ 96,681	$ 63,214
Oil and natural gas	56,864	37,990
Gas gathering and processing	18,230	30
Other	(195)	376
Total revenues	171,580	101,610
Expenses:		
Contract drilling:		
Operating costs	63,431	46,556
Depreciation	9,610	7,464
Oil and natural gas:		
Operating costs	12,413	9,632
Depreciation, depletion and amortization	14,432	10,177
Gas gathering and processing:		
Operating costs	16,834	15
Depreciation	638	17
General and administrative	3,971	2,771
Interest	687	417
Total expenses	122,016	77,049
Income Before Income Taxes	49,564	24,561
Income Tax Expense:		
Current	9,417	571
Deferred	9,417	8,763
Total income taxes	18,834	9,334
Equity in Earnings of Unconsolidated Investments, Net of Income Tax	--	280
Net income	$ 30,730	$ 15,507
Net Income per Common Share:		
Basic	$ 0.67	$ 0.34
Diluted	$ 0.67	$ 0.34

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

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

	Three Months Ended March 31,	
	2005	**2004**
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 30,730	$ 15,507
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion and amortization	24,874	17,886
Deferred tax expense	9,417	8,935
Other	1,246	(17)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(10,448)	899
Accounts payable	(10,781)	(2,388)
Material and supplies inventory	(1,078)	(2,386)
Accrued liabilities	13,277	1,670
Prepaid expenses	(214)	(565)
Contract advances	(1,145)	2,955
Other - net	16	116
Net cash provided by operating activities	55,894	42,612
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (including producing property acquisitions and other acquisitions)	(47,121)	(124,324)
Proceeds from disposition of assets	2,328	1,023
Other-net	(207)	350
Net cash used in investing activities	(45,000)	(122,951)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(17,500)	74,600
Net payments of notes payable and other long-term debt	276	--
Proceeds from exercise of stock options	517	219
Book overdrafts	5,618	5,299
Net cash from (used in) financing activities	(11,089)	80,118
Net Decrease in Cash and Cash Equivalents	(195)	(221)
Cash and Cash Equivalents, Beginning of Year	665	598
Cash and Cash Equivalents, End of Period	$ 470	$ 377

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 March 31,	
	2005	2004
	(In thousands)	
Net Income	$ 30,730	$ 15,507
Other Comprehensive Income, Net of Taxes:		
Change in value of cash flow derivative instruments used as cash flow hedges	(1,464)	(304)
Adjustment reclassification - derivative settlements	28	78
Comprehensive Income	$ 29,294	$ 15,281

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

NOTE 1 - BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited consolidated condensed financial statements include the accounts of Unit Corporation and its wholly owned subsidiaries ("company") and have been prepared under the rules and regulations of the Securities and Exchange Commission. 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 generally accepted accounting principles. 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 present fairly the interim financial information. Certain reclassifications have been made to prior year financial information to conform to the current period presentation.

Results for the three months ended March 31, 2005 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, 2004. The company's independent registered public accounting firm performed a review of these interim financial statements in accordance with standards of the Public Company Accounting Oversight Board (United States). Under Rule 436(c) under the Securities Act of 1933, their report of that review should not be considered as part of any registration statements prepared or certified by them within the meaning of Section 7 and 11 of that Act and the independent registered public accounting firm's liability under Section 11 does not extend to it.

The company's stock-based compensation plans are accounted for under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense included in reported net income is the company's matching 401(k) contribution. The following table illustrates the effect on net income and earnings per share if the company had applied the fair value recognition provisions of Financial Accounting Standards Board Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	Three Months Ended	
	2005	2004
	(In thousands except per share amounts)	
Net Income, as Reported	$ 30,730	$ 15,507
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax	549	219
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(1,030)	(513)
Pro Forma Net Income	$ 30,249	$ 15,213
Basic Earnings per Share:		
As reported	$ 0.67	$ 0.34
Pro forma	$ 0.66	$ 0.33
Diluted Earnings per Share:		
As reported	$ 0.67	$ 0.34
Pro forma	$ 0.66	$ 0.33

The fair value of each option granted is estimated using the Black-Scholes model. There were no options granted in the first quarter of 2004. In the first quarter of 2005 options for 4,000 shares with an estimated fair market value of approximately $80,101 were granted. For options granted in 2005, the company's estimate of stock volatility was 0.55 based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 4.42. Expected life ranged from 1 to 10 years based on prior experience depending on the vesting periods involved and the make up of participating employees.

NOTE 2 - EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share for the company.

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
For the Three Months Ended March 31, 2005:			
Basic earnings per common share	$ 30,730	45,800	$ 0.67
Effect of dilutive stock options	--	250	--
Diluted earnings per common share	$ 30,730	46,050	$ 0.67
For the Three Months Ended March 31, 2004:			
Basic earnings per common share	$ 15,507	45,671	$ 0.34
Effect of dilutive stock options	--	188	--
Diluted earnings per common share	$ 15,507	45,859	$ 0.34

All of the stock options outstanding at March 31, 2005 and 2004 were included in the computation of diluted earnings per share for the three months ended March 31, 2005 and 2004.

NOTE 3 - ACQUISITIONS

On January 5, 2005 the company acquired a subsidiary of Strata Drilling LLC for $10.5 million in cash. In this acquisition the company acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two rigs are 1,500 horsepower, diesel electric rigs with the capacity to drill 12,000 to 20,000 feet. One rig was operating under contract when acquired and the other rig will require approximately $2 million in expenditures before it will be placed in service. The latter rig should be fully operational during the second quarter of 2005. Both rigs will be 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.

The $10.5 million paid in this acquisition was allocated as follows (in thousands):

Rigs	$ 5,712
Spare Drilling Equipment	2,715
Drill Pipe and Collars	932
Goodwill	1,106
Total consideration	$ 10,465

NOTE 4 - CREDIT AGREEMENT

Long-term debt consisted of the following as of March 31, 2005 and 2004:

	2005	**2004**
	(In thousands)	
Revolving Credit Loan, with Interest at March 31, 2005 and 2004 of 3.7% and 2.2%, Respectively	$ 78,000	$ 75,000
Less Current Portion	--	--
Total Long-Term Debt	$ 78,000	$ 75,000

On January 30, 2004, in conjunction with the company's acquisition of PetroCorp Incorporated, the company replaced its credit agreement with a revolving $150 million credit facility having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount and the company has elected to have the full $150.0 million available as the commitment amount. The company pays a commitment fee of .375 of 1% for any unused portion of the commitment amount. The company incurred origination, agency and syndication fees of $515,000 associated with the new agreement, $40,000 of which will be paid annually. The fees will be amortized over the four year life 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. Each re-determination is based primarily on the sum of a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of the company's drilling rig fleet, limited to $20 million, is added to the borrowing base. The agreement also allows for one requested special re-determination of the borrowing base (by either the lender or the company) between each scheduled re-determination date if conditions warrant such a request.

At the company's election, any part of the outstanding debt may be fixed at a 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 to the administrative agent 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.

The credit 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 that the company have at the end of each quarter:

- consolidated net worth of at least $350 million,
- a current ratio (as defined in the loan 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 the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On March 31, 2005, the company was in compliance with the covenants of its credit agreement.

NOTE 5 - ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) the company is required to record the fair value of liabilities associated with the retirement of long-lived assets. The company owns oil and natural gas properties which require cash to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. 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 plugging liabilities.

The following table shows the activity for the three months ending March 31, 2005 and 2004 relating to the company's retirement obligation for plugging liability:

	Three Months Ended 2005	Three Months Ended 2004
	(In Thousands)	
Short-Term Plugging Liability:		
Liability at beginning of period	$ 226	$ 303
Accretion of discount	8	4
Liability settled in the period	--	(57)
Plugging liability at end of period	$ 234	$ 250
Long-Term Plugging Liability:		
Liability at beginning of period	$ 18,909	$ 11,691
Accretion of discount	234	173
Liability incurred in the period	144	5,566
Liability settled in the period	(23)	--
Sold	--	(17)
Revision of estimate	(2)	--
Plugging liability at end of period	$ 19,262	$ 17,413

NOTE 6 - NEW ACCOUNTING PRONOUNCEMENTS

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. The company does not expect this statement to have a material impact on its results of operations, financial condition or cash flows.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended Accounting Principles Board (APB) Opinion No. 29, "Accounting for Non-monetary Transactions." FAS 153 requires that non-monetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for non-monetary transactions occurring in fiscal periods beginning after June 15, 2005. The company does not expect this statement to have a material impact on its results of operations, financial condition or cash flows.

In December 2004, the FASB issued FAS 123R, which requires that compensation cost relating to share-based payments be recognized in the company's financial statements. The company currently accounts for those payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under Statement No. 123R, Unit would have been required to implement the standard as of the beginning of the first interim period that begins after June 15, 2005. On April 15, 2005, the Securities and Exchange Commission (SEC) approved a new rule that allows the implementation of Statement No. 123R at the beginning of the next fiscal year after June 15, 2005 (January 1, 2006 for Unit). The company is preparing to implement this standard effective January 1, 2006. On March 29, 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) on FAS 123R to assist preparers by simplifying some on the implementation challenges of FAS123R. In SAB 107, the SEC staff acknowledges that there exists a range of potential conduct, conclusions, or methodologies that reasonably could be applied in estimating fair values of share-based arrangements; thus, if a registrant makes a good-faith estimate in accordance with the provisions of FAS123R, future events that affect an instrument's fair value will not cast a doubt concerning the reasonableness of the original estimate. Although the transition method to be used to adopt the standard has not been selected, see Note 1 for the effect on net income and earnings per share for the three months ended March 31, 2005 and 2004 if the company had applied the fair value recognition provision of FAS 123 to stock based employee compensation.

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 LLC over the fair value of the net assets acquired. For goodwill and intangible assets recorded in the financial statements, an impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to the drilling segment. In the first quarter of 2005, the carrying amount of goodwill was increased $1.1 million for the goodwill recorded in the acquisition of Strata Drilling LLC.

NOTE 8 - HEDGING ACTIVITY

The company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on 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. Initial adoption of this standard was not material.

During the first and second quarters of 2004, the company entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covered the period of April through October of 2004 and had a floor of $4.50 and a ceiling of $6.76. The other contract covered the period of May through October of 2004 and had a floor of $5.00 and a ceiling of $7.00. The company also entered into an oil hedge covering 1,000 barrels of oil production per day. This transaction covered the periods of February through December of 2004 and had an average price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contract and the hedge was recognized on the March 31, 2004 balance sheet as a derivative liability of $365,000 and at a loss of $226,000, net of tax, in accumulated other comprehensive income. Oil revenues were reduced by $127,000 for the quarter due to the settlement of the oil hedge in February and March of 2004.

In January 2005, the company entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.19. The other contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.30. In March 2005, the company also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covers the period of April through December of 2005 and has a floor of $45.00 and a ceiling of $69.25. These hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the March 31, 2005 balance sheet as a derivative liability of $2.7 million and at a loss of $1.6 million, net of tax, in accumulated other comprehensive income.

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 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. The company's interest expense was increased by $46,500 in the first quarter of 2005 and the fair value of the swap was recognized on the March 31, 2005 balance sheet as a derivative asset of $333,000 and at a gain of $207,000, 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, representing its 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 development, acquisition and production of oil and natural gas properties and the Gas Gathering and Processing segment is engaged in the purchasing, gathering, processing and treating of natural gas.

The company evaluates the performance of its 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 industry segment for the three month periods ended March 31, 2005 and 2004 is as follows:

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(In thousands)	
Revenues:		
Contract drilling	$ 99,320	$ 65,580
Elimination of inter-segment revenue	2,639	2,366
Contract drilling net of inter-segment revenue	96,681	63,214
Oil and natural gas	56,864	37,990
Gas gathering and processing	20,088	335
Elimination of inter-segment revenue	1,858	305
Gas gathering and processing net of inter-segment revenue	18,230	30
Other	(195)	376
Total revenues	$ 171,580	$ 101,610

	Three Months Ended March 31, 2005	2004
	(In thousands)	
Operating Income (1):		
Contract drilling	$ 23,640	$ 9,194
Oil and natural gas	30,019	18,181
Gas gathering and processing	758	(2)
Total operating income	54,417	27,373
General and administrative expense	(3,971)	(2,771)
Interest expense	(687)	(417)
Other income (expense) – net	(195)	376
Income before income taxes	$ 49,564	$ 24,561

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying consolidated condensed balance sheet of Unit Corporation and its subsidiaries as of March 31, 2005, and the related consolidated condensed statements of income and comprehensive income for each of the three month periods ended March 31, 2005 and 2004 and the consolidated condensed statement of cash flows for the three month periods ended March 31, 2005 and 2004. 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 review 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, 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 auditing standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, shareholders' equity and cash flows for the year then ended, management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the company's internal control over financial reporting as of December 31, 2004; and in our report dated March 14, 2005, 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, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 3, 2005

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

FINANCIAL CONDITION

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

- the prices we receive for our natural gas production and, to a lesser extent, the prices we receive for our oil production;
- the quantity of natural gas 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.

At March 31, 2005, we had cash totaling $470,000 and we had borrowed $78.0 million of the $150.0 million we had elected to have available under our credit agreement.

Our three principal business segments are:

- contract drilling carried out by our subsidiaries Unit Drilling Company and Service Drilling Southwest, L.L.C.;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company and, until it was merged into Unit Petroleum Company in March 2005, PetroCorp Incorporated; and
- natural gas purchasing, gathering and processing carried out by our subsidiary Superior Pipeline Company, L.L.C.

The following is a summary of certain financial information on March 31, 2005 and March 31, 2004 and for the three months ended March 31, 2005 and March 31, 2004:

	March 31, 2005	March 31, 2004	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 31,981	$ 25,668	25%
Long-Term Debt	$ 78,000	$ 75,000	4%
Shareholders' Equity	$ 639,968	$ 532,673	20%
Ratio of Long-Term debt to Total Capitalization	11%	12%	
Net Income	$ 30,730	$ 15,507	98%
Net Cash Provided by Operating Activities	$ 55,894	$ 42,612	31%
Net Cash Used in Investing Activities	$ (45,000)	$ (122,951)	63%
Net Cash Provided by (Used In) Financing Activities	$ (11,089)	$ 80,118	(114%)

The following table summarizes certain operating information for the first three months of 2005 and 2004:

	2005	2004	Percent Change
Oil Production (MBbls)	280	215	30%
Natural Gas Production (MMcf)	7,653	6,294	22%
Average Oil Price Received	$ 44.56	$ 30.63	45%
Average Oil Price Received Excluding Hedge	$ 44.56	$ 31.22	43%
Average Natural Gas Price Received	$ 5.69	$ 4.90	16%
Average Natural Gas Price Received Excluding Hedge	$ 5.69	$ 4.90	16%
Average Number of Our Drilling Rigs in Use During the Period	99.3	81.7	22%
Total Number of Our Drilling Rigs Available at the End of the Period	102	88	16%
Gas Gathered - MMBtu/day	107,254	12,637	749%
Gas Processed - MMBtu/day	30,336	64	47,300%
Number of Natural Gas Gathering Systems	32	15	113%

Our Bank Credit Agreement. At March 31, 2005, we had a $150.0 million bank credit agreement consisting of a revolving credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and we currently elected to have the full $150.0 million available as the commitment amount. 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 associated with the new agreement, $40,000 of which will be paid annually. The remainder of the fees will be amortized over the four year life of the loan. The average interest rate for the first quarter of 2005 was 3.9%. At March 31, 2005 and May 2, 2005 our borrowings were $78.0 million and $67.5 million, respectively.

The borrowing base under our credit facility is subject to re-determination on May 10 and November 10 of each year. The latest re-determination supported the full $150.0 million. Each re-determination is based primarily on the sum of a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of our drilling rig fleet, limited to $20 million, is added to the borrowing base. The agreement also allows for one requested special re-determination of the borrowing base (by either the lender or us) between each scheduled re-determination date if conditions warrant such a request.

At our election, any part of the outstanding debt may be fixed at a 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 to the administrative agent 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 March 31, 2005, all of our $78.0 million debt was subject to the LIBOR Rate.

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

- consolidated net worth of at least $350 million,

- a current ratio (as defined in the loan 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 the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

We were in compliance with the covenants of our credit agreement as of March 31, 2005.

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 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. Our interest expense was increased by $46,500 in the first quarter of 2005 and the fair value of the swap was recognized on the March 31, 2005 balance sheet as a derivative asset of $333,000 and at a gain of $207,000, net of tax, in accumulated other comprehensive income.

Contractual Commitments. At March 31, 2005 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)	$ 86,619	$ 3,039	$ 83,580	$ --	$ --
Retirement Agreements(2)	2,162	350	1,219	593	--
Operating Leases(3)	3,592	995	1,543	1,054	--
Drill Pipe and Engine					

Acquisitions(4)	13,567	13,567	--	--	--
Tubing and Casing Acquisitions(5)	2,457	2,457	--	--	--
SerDrilco Inc. Earn-Out Agreement(6)	1,890	1,890	--	--	--
Total Contractual Obligations	$110,287	$22,298	$ 86,342	$1,647	$ --

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(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt. This obligation is presented in accordance with the terms of the credit agreement signed on January 30, 2004 and includes interest calculated at the March 31, 2005 interest rate of 3.7% including the effect of the interest rate swap related to $50.0 million of debt outstanding.

(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 payment 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 and Midland, Texas 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) Due to the increasing cost of steel and the potential for limited availability of new drill pipe within the industry, we have a

commitment to purchase approximately $11.8 million of drill pipe and drill collars. We have also committed to purchase $1.8 million of engines and generators for the construction of new rigs.

(5) Our oil and natural gas segment has a commitment to purchase $2.5 million of tubing and casing for delivery during the second and third quarter of 2005.

(6) On December 8, 2003, the company acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain 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, 2004, the drilling rigs included in the earn-out provision had cash flow of approximately $13.8 million.

At March 31, 2005, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Amount Committed Or Accrued	Amount of Commitment Expiration Per Period: Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred Compensation Agreement(1)	$ 2,334	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,898	$ 770	$ 225	Unknown	Unknown
Plugging Liability(3)	$ 19,496	$ 234	$ 551	$ 1,877	$ 16,834
Gas Balancing Liability(4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations(5)	Unknown	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability(6)	$ 17,525	$ 6,281	$ 1,998	$ 1,149	$ 8,097

(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 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 Unit 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 Unit 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 Unit. As of March 31, 2005, there were no participants the Special 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 2004, with a subsidiary of ours serving as General Partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. No repurchases were made in the first quarter of 2005 and 2004.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims made primarily in 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.

During the first and second quarters of 2004, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covered the period of April through October of 2004 and had a floor of $4.50 and a ceiling of $6.76. The other contract covered the period of May through October of 2004 and had a floor of $5.00 and a ceiling of $7.00. We also entered into an oil hedge covering 1,000 barrels of oil production per day. This transaction covered the periods of February through December of 2004 and had an average price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. The fair value of the collar contract and the hedge was recognized on the March 31, 2004 balance sheet as a derivative liability of $365,000 and at a loss of $226,000, net of tax, in accumulated other comprehensive income. Oil revenues were reduced by $127,000 for the quarter due to the settlement of the oil hedge in February and March of 2004.

In January 2005, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.19. The other contract covers the period of April through October of 2005 and has a floor of $5.50 and a ceiling of $7.30. In March 2005, we also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covers the periods of April through December of 2005 and has a floor of $45.00 and a ceiling of $69.25. These hedges are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the collar contracts was recognized on the March 31, 2004 balance sheet as a derivative liability of $2.7 million and at a loss of $1.6 million, net of tax, in accumulated other comprehensive income.

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 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. Our interest expense was increased by $46,500 in the first quarter of 2005 and the fair value of the swap was recognized on the March 31, 2005 balance sheet as a derivative asset of $333,000 and at a gain of $207,000, net of tax, in accumulated other comprehensive income.

Self-Insurance or Retentions. We are self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. Our insurance policies contain deductibles or retentions per occurrence ranging from $200,000 for general liability to $1.0 million for 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 claims. There is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco we have continued to use its ERISA governed occupational injury benefit plan to cover its employees 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 affect 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 quarter 2005 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $239,000 per month ($2.9 million annualized) change in our pre-tax operating cash flow. Our first quarter 2005 average natural gas price was $5.69 compared to an average natural gas price of $4.90 for the first quarter of 2004. A $1.00 per barrel change in our oil price would have a $86,800 per month ($1.0 million annualized) change in our pre-tax operating cash flow based on our production in the first quarter of 2005. Our first quarter 2005 average oil price was $44.56 compared with an average oil price of $30.63 received in the first quarter of 2004.

Because 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 affect 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.

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 26 wells (8.84 net wells) in the first quarter of 2005 compared to 34 wells (15.98 net wells) in the first quarter of 2004. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first quarter of 2005 totaled $31.6 million. Based on current prices, we plan to drill an estimated 220 to 230 wells in 2005 and estimate our total capital expenditures for oil and natural gas exploration and acquisitions to be around $125.0 million. We have commitments to purchase

$2.5 million of tubing and casing for delivery during the second quarter of 2005.

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 keeping all of the rig crews we need.

In response, at the end of the first and fourth quarters of 2004, we increased wages in some of our drilling areas and implemented longevity pay incentives to help maintain our contract drilling labor base. To date, these efforts have allowed us to meet our labor requirements. If current demand for drilling rigs continues, shortages of experienced personnel may limit our ability to operate our drilling rigs at or above the 98% utilization rate we achieved in the first quarter of 2005.

We currently do not have any shortages of drill pipe and drilling equipment. Because of increasing steel costs and the potential for shortages in the availability of new drill pipe, at March 31, 2005 we had commitments to purchase approximately $11.8 million of drill pipe and drill collars. We have also committed to purchase $1.8 million of engines and generators for the construction of new rigs.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices influence the demand for our drilling rigs and the prices we can charge for our contract drilling services. The average rates we received for our drilling rigs during 2003 and 2004 reached a low of $7,275 per day in February of 2003. However, as natural gas and oil prices began to rise during the second quarter of 2003 and have continued to remain strong through the first quarter of 2005, both demand for our drilling rigs and dayrates have improved. In the first quarter of 2005, the average dayrate we received was $10,253 per day compared to $8,252 per day in the first quarter of 2004. The average use of our drilling rigs in the first quarter of 2005 was 99.3 drilling rigs (98%) compared with 81.7 rigs (93%) for the first quarter of 2004. Based on the average utilization of our drilling rigs during the first quarter of 2005, a $100 per day change in dayrates has an $9,930 per day ($3.6 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.

Our contract drilling subsidiary provides 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 quarter of 2005 and 2004, we drilled 11 and 8 wells, respectively for our exploration and production subsidiary. The profit received by our contract drilling segment of $851,000 and $929,000 during the first quarter of 2005 and 2004, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

Drilling Acquisitions and Capital Expenditures. On January 5, 2005, we acquired a subsidiary of Strata Drilling LLC for $10.5 million in cash. This acquisition included 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. One drilling rig was operating under contract when it was acquired and the other drilling rig will require approximately $2 million in expenditures before it will be placed in service. The latter rig should be fully operational during the second quarter of 2005. Both rigs will be 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 July 30, 2004, we completed our acquisition of Sauer Drilling Company, a Casper, Wyoming-based drilling company. We paid $40.3 million in in this acquisition which included $5.3 million for working capital. This acquisition includes nine drilling rigs, a fleet of trucks, and an equipment and repair yard with associated inventory, located in Casper, Wyoming. The rigs range from 500 horsepower to 1,000 horsepower with depth capacities rated from 5,000 feet to 16,000 feet. The fleet of trucks consists of four vacuum trucks and 11 rig-up trucks used to move the rigs to new drilling locations. The trucks also have the capacity to move third-party rigs. This acquisition increased our market share in the Rocky Mountains in the medium-to-smaller drilling rig depth ranges. The Casper, Wyoming equipment yard, will continue to provide service space for the nine newly acquired drilling rigs and trucks as well as for our existing Rocky Mountain rig fleet. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004.

On May 4, 2004, we acquired two drilling rigs and related equipment for $5.5 million. The drilling rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. We refurbished the drilling rigs for approximately $4.0 million. One drilling rig was placed into service at the beginning of August 2004 and the other drilling rig was placed into service in the middle of September 2004. Both drilling rigs are working in our Rocky Mountain division.

For our contract drilling operations, during the first quarter of 2005, we incurred $26.0 million in capital expenditures, which includes $1.1 million in goodwill from the Strata Drilling LLC acquisition. For the year 2005, we have budgeted capital expenditures of approximately $60 million for our contract drilling operations excluding the $10.5 million paid in the Strata Drilling LLC acquisition.

Acquisition of Natural Gas Gathering and Processing Company. In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior Pipeline Company, L.L.C. we did not already own. We paid $19.8 million in this acquisition. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas. It operates one natural gas treatment plant, owns three processing plants, 32 active gathering systems and 440 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana and has been in business since 1996. This acquisition and consolidation increases our ability to gather and market our natural gas (as well as third party natural gas) and construct or acquire existing natural gas gathering and processing facilities.

Before this acquisition, our 40% interest in the operations of Superior was shown as equity in earnings of unconsolidated investments. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. During the first quarter of 2005, Superior purchased $1.3 million of our natural gas production and paid $32,000 for our natural gas liquids which were eliminated from our consolidated condensed financial statements.

For the year 2005, we have budgeted capital expenditures of approximately $20.0 million for our natural gas gathering and processing operation with the focus on growing this segment through the construction of new facilities or acquisitions.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 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 2004, the total paid to us for all of these fees was $746,000. We expect the fees in 2005 will be comparable to those in 2004. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

NEW ACCOUNTING PRONOUNCEMENTS

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. We do not expect this statement to have a material impact on our results of operations, financial condition or cash flows.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended Accounting Principles Board (APB) Opinion No. 29, "Accounting for Non-monetary Transactions." FAS 153 requires that non-monetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for non-monetary transactions occurring in fiscal periods beginning after June 15, 2005. We do not expect this statement to have a material impact on our results of operations, financial condition or cash flows.

In December 2004, the FASB issued FAS 123R, which requires that compensation cost relating to share-based payments be recognized in our financial statements. We currently account for those payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under Statement No. 123R, we would have been required to implement the standard as of the beginning of the first interim period that begins after June 15, 2005. On April 15, 2005, the Securities and Exchange Commission (SEC) approved a new rule that allows the implementation of Statement No. 123R at the beginning of the next fiscal year that begins after June 15, 2005 (January 1, 2006 for us). We are preparing to implement this standard effective January 1, 2006. On March 29, 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107) on FAS 123R to assist preparers by simplifying some on the implementation challenges of FAS123R. In SAB 107, the SEC staff acknowledges that there exists a range of potential conduct, conclusions, or methodologies that reasonably could be applied in estimating fair values of share-based arrangements; thus, if a registrant makes a good-faith estimate in accordance with the provisions of, future events that affect an instrument's fair value will not cast a doubt concerning the reasonableness of the original estimate. Although the transition method to be used to adopt the standard has not been selected, see Note 1 for the effect on net income and earnings per share for the three months ended March 31, 2005 and 2004 if we had applied the fair value recognition provision of FAS 123 to stock based employee compensation.

SAFE HARBOR STATEMENT

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

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

- the amount and nature of our future capital expenditures;
- 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. 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.

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines certain factors that in the future could cause our consolidated results for 2005 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

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 Securities and Exchange Commission. We encourage you to get and read that document.

RESULTS OF OPERATIONS

First Quarter 2005 versus First Quarter 2004

Provided below is a comparison of selected operating and financial data for the first quarter of 2005 versus the first quarter of 2004:

	First Quarter 2005	First Quarter 2004	Percent Change
Total Revenue	$ 171,580,000	$ 101,610,000	69%
Net Income	$ 30,730,000	$ 15,507,000	98%
Oil and Natural Gas:			
Revenue	$ 56,864,000	$ 37,990,000	50%
Operating costs	$ 12,413,000	$ 9,632,000	29%
Average natural gas price (Mcf)	$ 5.69	$ 4.90	16%
Average oil price (Bbl)	$ 44.56	$ 30.63	45%
Natural gas production (Mcf)	7,653,000	6,294,000	22%
Oil production (Bbl)	280,000	215,000	30%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.54	$ 1.33	16%
Depreciation, depletion and amortization	$ 14,432,000	$ 10,177,000	42%
Drilling:			
Revenue	$ 96,681,000	$ 63,214,000	53%
Operating costs	$ 63,431,000	$ 46,556,000	36%
Percentage of revenue from daywork contracts	100%	100%	
Average number of rigs in use	99.3	81.7	22%
Average dayrate on daywork contracts	$ 10,253	$ 8,252	24%
Depreciation	$ 9,610,000	$ 7,464,000	29%
Gas Gathering and Processing:			
Revenue	$ 18,230,000	$ 30,000	60,667%
Operating costs	$ 16,834,000	$ 15,000	112,127%
Depreciation	$ 638,000	$ 17,000	3,653%
Gas gathered - Mmbtu/day	107,254	12,637	749%
Gas processed - Mmbtu/day	30,336	64	47,300%
General and Administrative Expense	$ 3,971,000	$ 2,771,000	43%
Interest Expense	$ 687,000	$ 417,000	65%
Average Interest Rate	3.74%	2.19%	71%
Average Long-Term Debt Outstanding	$ 94,056,000	$ 56,019,000	68%

Oil and natural gas revenues increased $18.9 million or 50% in the first quarter of 2005 as compared to the first quarter of 2004. Increased oil and natural gas prices accounted for 53% of this increase while increased production volumes accounted for 47% of the increase. The PetroCorp acquisition increased oil production by 16% in the first quarter of 2005 while total oil production increased 30%. The PetroCorp acquisition increased natural gas production for the first quarter of 2005 by 6% while total natural gas production increased 22%. Since PetroCorp was purchased on January 30, 2004, there is an additional month of PetroCorp production volumes in the first quarter of 2005. Increased production outside of the PetroCorp acquisition came primarily from our development drilling.

Oil and natural gas operating costs increased $2.8 million or 29% in the first quarter of 2005 as compared to 2004. Costs directly related to the production of the PetroCorp wells that we acquired in January 2004 represented 22% of this increase while 26% came from production costs related to wells we drilled in 2004 and increases in production costs from previously owned wells. Gross production taxes represented 36% of the increase because of higher oil and natural gas revenues. General and administrative cost directly related to well production represented 12% of the increase as labor costs increased primarily because of a 41% addition in the number of employees working in the exploration and production area. Total depreciation, depletion and amortization ("DD&A") increased $4.3 million or 42%. Higher production volumes accounted for 56% of this increase while increases in our DD&A rate represented 44% of this increase. The increase in our DD&A rate in the first quarter of 2005 compared to the first quarter of 2004 resulted primarily from 63% higher development drilling cost per equivalent Mcf in 2004. PetroCorp's oil and natural gas reserves were added at a 5% higher cost per Mcfe than our discovery cost in 2003.

Industry demand for our drilling rigs increased throughout 2004 and the first quarter of 2005 as natural gas prices continued to remain above $4.50. Drilling revenues increased $33.5 million or 53% in the first quarter of 2005 versus the first quarter of 2004. In July 2004, we acquired nine drilling rigs with the acquisition of Sauer Drilling Company. The Sauer drilling rigs increased our first quarter 2005 drilling revenues by approximately 16%. In addition to the Sauer drilling rigs, we also placed four additional drilling rigs in service since the first quarter of 2004. The increase in revenue from all of the acquired drilling rigs and the increase in utilization of our previously owned drilling rigs represented 39% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 61% of the increase in total drilling revenues. Our average dayrate in the first quarter of 2005 was 24% higher than in the first quarter of 2004.

Drilling operating costs increased $16.9 million or 36% between the comparative quarters. The increase in operating costs from all of the 14 drilling rigs place in service since the first quarter of 2004 and increased utilization of our previously owned drilling rigs represented 55% of the total increase in operating cost. Increases in operating cost per day accounted for 45% of the increase in total operating costs. Operating cost per day increased $835 per day in the first quarter of 2005 when compared with the first quarter of 2004. Approximately $609 of that increase was from costs directly associated with the drilling of wells with increases in labor cost the primary cause of the increase. Indirect drilling costs made up most of the remainder of the increase in per day costs and consisted primarily of property taxes, safety related expenses, repairs and the implementation of a central hiring system for our Oklahoma drilling rigs. We expect the demand for drilling rigs to remain high throughout 2005 and this demand will increase our drilling rig expenses. We did not drill any turnkey or footage wells in 2004 or in the first quarter of 2005. Contract drilling depreciation increased $2.1 million or 29%. The acquisition of the 14 drilling rigs placed in service since the first quarter of 2004 increased depreciation $1.1 million or 14% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior we did not already own. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior's operations. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas and operates one natural gas treatment plant and owns three processing plants, 32 active gathering systems and 440 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana.

Before the Superior acquisition, our 40% interest in the income or loss from the operations of Superior was shown as equity in earnings of unconsolidated investments and was $280,000 net of income tax in the first quarter of 2004. The results of operations for Superior are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. Our natural gas gathering and processing revenues, operating expenses and depreciation were $18.2 million, $16.8 million and $0.6 million higher in the first quarter of 2005 versus 2004, respectively, all due to the Superior acquisition.

General and administrative expense increased $1.2 million or 43%. Personnel costs increased $1.0 million with $0.7 million of the personnel cost increase coming from the recognition of a liability associated with the retirement of Mr. John Nikkel from his position as Chief Executive Officer.

Total interest expense increased $0.3 million or 65%. Average debt outstanding was higher in the first quarter of 2005 as compared to the first quarter of 2004 due to the PetroCorp, Superior, Sauer and Strata acquisitions in 2004 and 2005. The increase in average debt outstanding accounted for approximately 64% of the interest expense increase with the remaining 36% coming from an increase in average interest rates. In association with our development of oil and natural gas properties and the construction of new drilling rigs and natural gas gathering systems, we capitalized $311,000 of interest in the first quarter of 2005. No interest was capitalized in 2004.

Income tax expense increased $9.3 million or 98% due to the increase in income before income taxes. Our effective tax rate for the first quarter of 2005 was 38.0% versus 38.1% in the first quarter of 2004.

Other revenues decreased $0.6 million. Other revenues include $0.7 million loss from the write-off of the net book value associated with equipment lost in the collapse of rig number 306's derrick on March 10, 2005. The rig was repaired and resumed drilling operations in the early part of April.

Item 3. Quantitative and Qualitative Disclosures 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. The price we receive is 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 quarter 2005 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $239,000 per month ($2.9 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $86,800 per month ($1.0 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 Operation included above.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the 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 Operation included above. Based on our average outstanding long-term debt subject to the floating rate in the first quarter of 2005, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $441,000.

Item 4. 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 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries).

There were no changes in the company's internal controls or in other factors that could significantly affect these internal controls subsequent to the date of our most recent evaluation.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

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: May 3, 2005

By: /s/ Larry D. Pinkston

LARRY D. PINKSTON
Chief Executive Officer and Director

Date: May 3, 2005

By: /s/ David T. Merrill

DAVID T. MERRILL
Chief Financial Officer and Treasurer

Exhibit 15

May 3, 2005

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Commissioners:

We are aware that our report dated May 3, 2005 on our review of interim financial information of Unit Corporation for the three month periods ended March 31, 2005 and 2004 and included in the Company's quarterly report on Form 10-Q for the quarter ended March 31, 2005 is incorporated by reference in its registration statements on Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166 and 333-39584) and Form S-3 (File No.’s 333-83551 and 333-99979).

Yours very truly,

PricewaterhouseCoopers LLP

Exhibit 31.1

TRANSITIONAL FORM OF SECTION 302 CERTIFICATIONS FOR ACCELERATED FILER

I, Larry D. Pinkston, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(c) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2005

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

Exhibit 31.2

TRANSITIONAL FORM OF SECTION 302 CERTIFICATIONS
FOR ACCELERATED FILER

I, David T. Merrill, certify that:

1. I have reviewed this quarterly report on form 10-Q of Unit Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(c) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2005

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

Exhibit 32

CERTIFICATION
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (A) AND (B) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Unit Corporation a Delaware corporation (the "Company"), does hereby certify, to such officer's knowledge, that:

The Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of March 31, 2005 and March 31, 2004 and for the quarters ended March 31, 2005 and 2004.

Dated: May 3, 2005

By: /s/ Larry D. Pinkston

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Larry D. Pinkston
Chief Executive Officer

Dated: May 3, 2005

By: /s/ David T. Merrill

____

David T. Merrill
Chief Financial Officer and
Treasurer

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-Q or as a separate disclosure document.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Unit Corporation and will be retained by Unit Corporation and furnished to the Securities and Exchange Commission or its staff on request.