SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2003
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.)**

1000 Kensington Tower I,
7130 South Lewis,

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 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	**43,528,910**
Class	**Outstanding at August 8, 2003**

FORM 10-Q
UNIT CORPORATION

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS (UNAUDITED)

	December 31, 2002	June 30, 2003
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 497	$ 1,326
Accounts receivable	33,912	47,453
Materials and supplies	8,794	7,183
Income tax receivable	3,602	705
Other	4,594	3,834
Total current assets	51,399	60,501
Property and Equipment:		
Drilling equipment	369,777	376,662
Oil and natural gas properties, on the full cost method		
Proved properties	449,226	482,617
Undeveloped leasehold not being amortized	16,024	19,008
Transportation equipment	6,856	7,403
Other	9,906	12,044
	851,789	897,734
Less accumulated depreciation, depletion, amortization and impairment	341,031	357,222
Net property and equipment	510,758	540,512
Goodwill	12,794	12,794
Other Assets	3,212	6,442
Total Assets	$ 578,163	$ 620,249

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

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

	December 31, 2002	June 30, 2003
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term liabilities and debt	$ 1,465	$ 736
Accounts payable	21,119	19,545
Accrued liabilities	11,948	13,381
Total current liabilities	34,532	33,662
Long-Term Debt	30,500	19,000
Other Long-Term Liabilities	5,439	17,399
Deferred Income Taxes	86,320	101,713
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, 43,339,400 and 43,525,310 shares issued, respectively	8,668	8,705
Capital in excess of par value	264,180	265,645
Accumulated other comprehensive income	-	(74)
Retained earnings	148,524	174,199
Total shareholders' equity	421,372	448,475
Total Liabilities and Shareholders' Equity	$ 578,163	$ 620,249

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2003	2002	2003
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 25,841	$ 45,221	$ 52,555	$ 79,787
Oil and natural gas	18,668	26,871	30,629	60,119
Other	244	888	299	1,520
Total revenues	44,753	72,980	83,483	141,426
Expenses:				
Contract drilling:				
Operating costs	20,137	33,641	39,269	61,452
Depreciation and amortization	2,928	5,899	5,739	10,793
Oil and natural gas:				
Operating costs	5,161	5,893	10,109	12,508
Depreciation, depletion and amortization	5,988	6,445	11,257	12,492
General and administrative	2,013	2,070	4,042	4,520
Interest	229	175	516	386
Total expenses	36,456	54,123	70,932	102,151
Income Before Income Taxes and Change in Accounting Principle	8,297	18,857	12,551	39,275
Income Tax Expense:				
Current	238	144	360	299
Deferred	2,951	7,022	4,441	14,626
Total income taxes	3,189	7,166	4,801	14,925
Income Before Change in Accounting Principle	5,108	11,691	7,750	24,350
Cumulative Effect of Change in Accounting Principle (Net of Income Tax of $811,000)	-	-	-	1,325
Net Income	$ 5,108	$ 11,691	$ 7,750	$ 25,675

=========   =========   =========   =========

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2003	2002	2003
	(In thousands except per share amounts)			
Basic Earnings Per Common Share:				
Income before change in accounting principle	$ 0.14	$ 0.27	$ 0.21	$ 0.56
Cumulative effect of change in accounting principle net of income tax	-	-	-	0.03
Net Income	$ 0.14	$ 0.27	$ 0.21	$ 0.59
Diluted Earnings Per Common Share:				
Income before change in accounting principle	$ 0.14	$ 0.27	$ 0.21	$ 0.56
Cumulative effect of change in accounting principle net of income tax	-	-	-	0.03
Net Income	$ 0.14	$ 0.27	$ 0.21	$ 0.59
Pro Forma Amounts Assuming Retroactive Application of Change in Accounting Principle:				
Net income	$ 5,081		$ 7,693	
Basic earnings per share	$ 0.14		$ 0.21	
Diluted earnings per share	$ 0.14		$ 0.21	

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

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

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2003
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 7,750	$ 25,675
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion, and amortization	17,313	23,621
Deferred tax expense	4,441	14,626
Other	198	(372)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	6,069	(13,788)
Accounts payable	4,050	3,417
Material and supplies inventory	(1,550)	1,611
Prepaid expenses	3,059	3,748
Contract advances	(91)	2,271
Other - net	(428)	(154)
Net cash provided by operating activities	40,811	60,655
Cash Flows From (Used In) Investing Activities:		
Capital expenditures	(29,188)	(42,104)
Proceeds from disposition of assets	907	520
Other-net	459	(2,498)
Net cash used in investing activities	(27,822)	(44,082)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(11,000)	(11,500)
Net payments of notes payable and other long-term debt	(22)	(1,020)
Proceeds from exercise of stock options	204	423
Book overdrafts	(1,104)	(3,647)
Net cash used in financing activities	(11,922)	(15,744)
Net Increase in Cash and Cash Equivalents	1,067	829
Cash and Cash Equivalents, Beginning of Year	391	497
Cash and Cash Equivalents, End of Period	$ 1,458	$ 1,326

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 June 30,		Six Months Ended June 30,	
	2002	2003	2002	2003
	(In thousands)			
Net Income	$ 5,108	$ 11,691	$ 7,750	$ 25,675
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	-	(233)	-	(78)
Reclassification of derivative settlements		4		4
Comprehensive Income	$ 5,108	$ 11,462	$ 7,750	$ 25,601

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 (the "Company") and have been prepared pursuant to 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.

Results for the three and six months ended June 30, 2003 are not necessarily indicative of the results to be realized during the full year. The condensed financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2002. Our independent accountants have performed a review of these interim financial statements in accordance with standards established by the American Institute of Certified Public Accountants. Pursuant to 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 accountants' liability under Section 11 does not extend to it.

Because the Company does not bear the risk of completion of wells drilled under daywork drilling contracts, it recognizes revenues and expenses generated from those contracts as the services are performed (i.e. daily). Under "footage" and "turnkey" contracts, revenues and expenses are recognized when the company has satisfied certain requirements as detailed in the applicable contracts. If it has been determined that a well is going to incur a loss, the entire amount of the estimated loss is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the terms of the contract are completed. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

Unit'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 Unit'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		**Six Months Ended**	
	2002	**2003**	**2002**	**2003**
	(In thousands except per share amounts)			
Net Income, as Reported	$ 5,108	$ 11,691	$ 7,750	$ 25,675
Add Stock Based Employee Compensation Expense Included in Reported Net Income - Net of Tax	160	168	320	335
Less Total Stock Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(333)	(471)	(599)	(875)
Pro Forma Net Income	$ 4,935	$ 11,388	$ 7,471	$ 25,135
Basic Earnings per Share:				
As reported	$ 0.14	$ 0.27	$ 0.21	$ 0.59
Pro forma	$ 0.14	$ 0.26	$ 0.21	$ 0.58
Diluted Earnings per Share:				
As reported	$ 0.14	$ 0.27	$ 0.21	$ 0.59
Pro forma	$ 0.14	$ 0.26	$ 0.21	$ 0.58

The fair value of each option granted is estimated using the Black-Scholes model. In the second quarter of 2002 and 2003 options were granted for 26,000 and 21,000 shares, respectively with an estimated fair value of approximately $320,000 and $262,000, respectively. For options granted in fiscal 2002 and in the second quarter of 2003, Unit's estimate of stock volatility was 0.53, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 4.24 and 3.6 percent in 2002 and the second quarter of 2003, respectively. 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.

Unit manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to Unit's satisfaction, or agree to assume liability for the remediation of the property.

To date, Unit has not experienced any substantial environmental liability. Any liabilities Unit has incurred have been small and have been timely resolved.

On August 15, 2002, Unit completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company. Both of these acquisitions were stock purchase transactions. Unit issued 6,819,748 shares of common stock and paid $3,813,053 for all the outstanding shares of CREC Rig Equipment Company and issued 400,252 shares of common stock and paid $686,947 for all the outstanding shares of CDC Drilling Company. The assets of the acquired companies included twenty drilling rigs, spare drilling equipment and vehicles. The purchase price for both transactions was determined through arms-length negotiations between the parties and only the cash portion of the transaction appears in the investing and financing activities of Unit's Consolidated Condensed Statement of Cash Flows. The results of operations for the acquired entities are included in the statement of operations for the periods beginning after August 15, 2002 and continuing through June 30, 2003.

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
For the Three Months Ended June 30, 2002:			
Basic earnings per common share	$ 5,108,000	36,109,000	$ 0.14
Effect of dilutive stock options	-	296,000	
Diluted earnings per common share	$ 5,108,000	36,405,000	$ 0.14
For the Three Months Ended June 30, 2003:			
Basic earnings per common share	$ 11,691,000	43,521,000	$ 0.27
Effect of dilutive stock options	-	228,000	
Diluted earnings per common share	$ 11,691,000	43,749,000	$ 0.27

All options and their average exercise prices for the three months ended June 30, 2003 were included in the computation of diluted earnings per share. The following options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended June 30, 2002 because the option exercise prices were greater than the average market price of common shares:

	2002
Options	21,000
Average exercise price	$ 20.10

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
For the Six Months Ended June 30, 2002:			
Basic earnings per common share	$ 7,750,000	36,072,000	$ 0.21
Effect of dilutive stock options	-	264,000	
Diluted earnings per common share	$ 7,750,000	36,336,000	$ 0.21
For the Six Months Ended June 30, 2003:			
Basic earnings per common share:			
Income before change in accounting principle	$ 24,350,000	43,477,000	$ 0.56
Cumulative effect of change in accounting principle net of income tax	1,325,000	43,477,000	0.03
Net Income	$ 25,675,000	43,477,000	$ 0.59
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		43,477,000	
Effect of dilutive stock options		213,000	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		43,690,000	
Income before change in accounting principle	$ 24,350,000	43,690,000	$ 0.56
Cumulative effect of change in accounting principle net of income tax	1,325,000	43,690,000	0.03
Net Income	$ 25,675,000	43,690,000	$ 0.59

The following options and their average exercise prices were not included in the computation of diluted earnings per share for the six months ended June 30, 2002 and 2003 because the option exercise prices were greater than the average market price of common shares:

	2002	**2003**
Options	174,000	21,000
Average exercise price	$ 17.19	$ 20.10

NOTE 3 - NEW ACCOUNTING PRONOUNCEMENTS

Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company and CDC Drilling Company over the fair value of the net assets acquired. Prior to January 1, 2002 goodwill was amortized on the straight-line method using a 25 year life. Unit expensed $243,000 annually for the amortization of goodwill. On July 20, 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("FAS 142"). For goodwill and intangible assets recorded in the financial statements, FAS 142 ended the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. FAS 142 became effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). Goodwill is all related to the drilling segment. In 2002 the carrying amount of Goodwill increased by $7,706,000 from the goodwill acquired in the acquisition of CREC Rig Equipment Company and CDC Drilling Company. Goodwill of $7,009,000 is expected to be deductible for tax purposes.

The following table shows the adjusted net income and earnings per share resulting from the removal of the amortization expense (net of income tax) recognized in the prior year ended periods:

	2000	2001	2002
	(In thousands except per share amounts)		
Adjusted Net Income:			
Reported net income	$ 34,344	$ 62,766	$ 18,244
Add back:			
Goodwill amortized - net of income tax	92	88	-
Adjusted net income	$ 34,436	$ 62,854	$ 18,244
Basic Earnings per Share:			
Reported net income	$ 0.96	$ 1.75	$ 0.47
Add back:			
Goodwill amortized - net of income tax	-	-	-
Adjusted basic earnings per share	$ 0.96	$ 1.75	$ 0.47
Diluted Earnings per Share:			
Reported net income	$ 0.95	$ 1.73	$ 0.47
Add back:			
Goodwill amortized - net of income tax	-	-	-
Adjusted diluted earnings per share	$ 0.95	$ 1.73	$ 0.47

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. Unit owns oil and natural gas properties which require expenditures 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). Unit does not have any assets restricted for the purpose of settling the plugging liabilities.

The following table shows the activity relating to our retirement obligation for plugging liability:

	Short Term Plugging Liability	Long Term Plugging Liability
	(In Thousands)	
Plugging Liability 1/1/03	$ 203	$ 10,632
Accretion of Discount	8	244
Liability Incurred in the Period	53	226
Liability Settled in the Period	-	(79)
Reclassification of Liability From Long to Short Term	37	(37)
Plugging Liability 6/30/03	$ 301	$ 10,986

The effect of this change increased net property, plant and equipment by $13.0 million and liabilities, including deferred tax liabilities, by $11.7 million at January 1, 2003 and decreased net income before change in accounting principle for the three and six month periods of 2003 by $37,000 ($0.00 per share) and $75,000 ($0.00 per share), respectively. The financial statements for the first three months of 2002 have not been restated and the cumulative effect of the change of $1,325,000 net of tax ($0.03 per share) is shown as a one-time addition to income in the first quarter of 2003.

The following table shows the adjusted net income and earnings per share resulting from the accretion of the discount and change in the depreciation, depletion and amortization (both net of income tax) as if the plugging liability had been recognized in the prior year ended periods:

	2000	2001	2002
	(In thousands except per share amounts)		
Adjusted Net Income:			
Reported net income	$ 34,344	$ 62,766	$ 18,244
Add back:			
Change in depreciation, depletion and amortization - net of income tax	80	156	167
Deduct:			
Accretion of discount - net of income tax	(231)	(260)	(296)
Adjusted net income	$ 34,193	$ 62,662	$ 18,115
Basic Earnings per Share:			
Reported net income	$ 0.96	$ 1.75	$ 0.47
Net adjustment to income from change in accounting principle	-	(0.01)	-
Adjusted basic earnings per share	$ 0.96	$ 1.74	$ 0.47
Diluted Earnings per Share:			
Reported net income	$ 0.95	$ 1.73	$ 0.47
Net adjustment to income from change in accounting principle	-	-	(0.01)
Adjusted diluted earnings per share	$ 0.95	$ 1.73	$ 0.46

At January 1, 2000 and December 31, 2000, 2001 and 2002 the plugging liability would have been $8,039,000, $8,673,000, $9,675,000 and $10,836,000, respectively, if FAS 143 had been applied during all the periods affected assuming the liability was measured using the information, assumptions and interest rates used as of the adoption date of January 1, 2003.

On January 1, 2003, we adopted Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13, and Technical Corrections" (FAS 145). This statement eliminates an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The adoption of FAS 145 did not have a material effect on our financial position, results of operations or cashflows.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Cost Associated with Exit or Disposal Activities" (FAS 146). FAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. FAS 146 nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." During the first six months of 2003, we did not have any exit or disposal activities.

In April 2003, the FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (FAS 149). FAS 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under FAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". Unit is currently evaluating the impact of FAS 149 on its financial position and results of operations.

In May 2003, the FASB issued Statement on Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (FAS 150). FAS 150 establishes standards regarding the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. FAS 150 will be effective for us starting in the quarter ended September 30, 2003. We do not expect the application of SFAS 150 to have a material effect on our financial position, results of operations or cashflow.

NOTE 4 – INTANGIBLE UNDEVELOPED LEASEHOLD AND INTANGIBLE DEVELOPED LEASEHOLD

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (FAS 142) were issued by the Financial Accounting Standards Board (FASB) in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the disclosures required by FAS 141 and 142 relative to intangibles would be included in the notes to financial statements. Historically, we, like many other oil and gas companies, have included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after FAS 141 and 142 became effective.

Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with full cost accounting rules.

At June 30, 2003, we had undeveloped leaseholds of approximately $15,811,000 that would be classified on our balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $20,163,000 that would be classified as "intangible developed leasehold" if we applied the interpretations. This classification would require us to make the disclosures set forth under FAS 142 related to these interests.

We will continue to classify our oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

NOTE 5 – HEDGING ACTIVITY

Periodically Unit hedges the price it will receive for a portion of its future natural gas and oil production. The hedge is made in an attempt to reduce the impact and uncertainty that price variations have on Unit’s cash flow.

During the first quarter of 2003, Unit entered into two natural gas collar contracts for approximately 37 percent of its April thru September 2003 production. One contract has a floor price of $4.00 and a ceiling price of $5.75 and the other contract has a floor price of $4.50 and a ceiling price of $6.02. During the first quarter of 2003, Unit also entered into two oil collar contracts for approximately 26 percent of its May thru December 2003 oil production. One contract has a floor price of $25.00 and a ceiling price of $32.20 and the other contact has a floor price of $26.00 and a ceiling price of $31.40. Unit had a $6,000 reduction in natural gas revenues as a result of the natural gas hedges settled in the second quarter of 2003. The fair value of the collar contracts still outstanding was recognized on the June 30, 2003 balance sheet as a derivative liability of $119,000 and as a $74,000 loss, net of tax, in accumulated other comprehensive income. These hedges were fully effective. Unit did not have any hedging contracts in place in the first six months of 2002.

NOTE 6 - INDUSTRY SEGMENT INFORMATION

The company has two business segments: Contract Drilling, and Oil and Natural Gas, representing its two strategic business units offering different products and services. The Contract Drilling segment provides land contract drilling of oil and natural gas wells and the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties. 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 and six month periods ended June 30, 2002 and 2003 is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2003	2002	2003
	(In thousands)			
Revenues:				
Contract drilling	$ 25,841	$ 45,221	$ 52,555	$ 79,787
Oil and natural gas	18,668	26,871	30,629	60,119
Other	244	888	299	1,520
	$ 44,753	$ 72,980	$ 83,483	$ 141,426
Operating Income (1):				
Contract drilling	$ 2,776	$ 5,681	$ 7,547	$ 7,542
Oil and natural gas	7,519	14,533	9,263	35,119
Total operating income	10,295	20,214	16,810	42,661
General and administrative expense	(2,013)	(2,070)	(4,042)	(4,520)
Interest expense	(229)	(175)	(516)	(386)
Other income - net	244	888	299	1,520
Income before income taxes and change in accounting principle	$ 8,297	$ 18,857	$ 12,551	$ 39,275

(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.

The cumulative effect of change in accounting principle recorded in the first quarter of 2003 of $1,325,000, net of $811,000 in income tax, is all related to the oil and natural gas segment.

NOTE 7 - SUBSEQUENT EVENT

On August 14, 2003 Unit signed a definitive agreement with PetroCorp Incorporated (AMEX - PEX) to acquire all the outstanding shares of PetroCorp. The purchase price under the agreement is approximately $182,000,000 and will be paid all in cash. The purchase price is subject to certain adjustments including $6,500,000 which will be place in escrow to settle or satisfy certain contingent tax and litigation liabilities if not resolved prior to closing. Consummation of the transaction is subject to several conditions typical of transactions of this nature including regulatory review and the approval by two-thirds of PetroCorp's shareholders. PetroCorp shareholders representing approximately 50% of the outstanding shares of PetroCorp have agreed to support the merger. PetroCorp is a Tulsa-based company that explores and develops oil and natural gas properties primarily in Texas and Oklahoma.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying consolidated condensed balance sheet of Unit Corporation and subsidiaries as of June 30, 2003, and the related consolidated condensed statements of operations and comprehensive income for each of the three and six month periods ended June 30, 2003 and 2002 and the statement of cash flows for the six month periods ended June 30, 2003 and 2002. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. 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 generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

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

We previously audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet as of December 31, 2002, and the related consolidated statements of operations, stockholder’s equity and of cash flows for the year then ended (not presented herein), and in our report, dated February 19, 2003, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers L L P

Tulsa, Oklahoma
July 23, 2003

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 two principal subsidiaries (Unit Drilling Company and Unit Petroleum Company) and borrowings under our bank loan agreement. At June 30, 2003, we had cash totaling $1.3 million and we had borrowed $19.0 million of the $40.0 million we have elected to have available under our loan agreement.

The following is a summary of certain financial information on June 30, 2002 and 2003 and for the six months ended June 30, 2002 and 2003:

	June 30, 2002	June 30, 2003	Percent Change
Income Before Change in Accounting Principle	$ 7,750,000	$ 24,350,000	214%
Net Income	$ 7,750,000	$ 25,675,000	231%
Net Cash Provided by Operating Activities	$ 40,811,000	$ 60,655,000	49%
Net Cash Used in Investing Activities	$ 27,822,000	$ 44,082,000	58%
Net Cash Used in Financing Activities	$ 11,922,000	$ 15,744,000	32%
Working Capital	$ 12,361,000	$ 26,839,000	117%
Long-Term Debt	$ 20,000,000	$ 19,000,000	(5%)
Shareholders' Equity	$ 288,179,000	$ 448,475,000	56%
Ratio of Long-Term debt to Total Capitalization	6%	4%	

The following table summarizes certain operating information for the first six months of 2002 and 2003:

	2002	2003	Percent Change
Oil Production (Bbls)	227,000	238,000	5%
Natural Gas Production (Mcf)	9,653,000	9,810,000	2%
Average Oil Price Received	$ 19.83	$ 27.86	40%
Average Natural Gas Price Received	$ 2.53	$ 5.34	111%
Average Number of Our Drilling Rigs in Use During the Period	33.0	57.0	73%
Total Number of Our Drilling			

Rigs Available at the End of the Period	55	75	36%

Our Bank Loan Agreement. On July 24, 2001, we signed a $100 million bank loan agreement. At our election, the amount currently available for us to borrow is $40 million. Although the current value of our assets would have allowed us to have access to the full $100 million, we elected to set the loan commitment at $40 million to reduce our financing costs since we are charged a facility fee of .375 of 1 percent on the amount available but not borrowed.

Each year, on April 1 and October 1, our banks redetermine the loan value of our assets. At the April 1, 2003 redetermination date, the banks confirmed that the value of our assets would allow us to have access to the full $100 million. This value is mainly based on an amount equal to 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 loan value. Our loan agreement provides for a revolving credit facility, which ends on May 1, 2005 followed by a three-year term loan. Borrowing under our loan agreement totaled $19.0 million at June 30, 2003 and July 23, 2003 our second quarter earnings release date.

Borrowings under the revolving credit facility bear interest at the Chase Manhattan Bank, N.A. prime rate ("Prime Rate") or the London Interbank Offered Rates ("Libor Rate") plus 1.00 to 1.50 percent depending on the level of debt as a percentage of the total loan value. After May 1, 2005, borrowings under the loan agreement bear interest at the Prime Rate or the Libor Rate plus 1.25 to 1.75 percent depending on the level of debt as a percentage of the total loan value. In addition, the loan agreement allows us to select, between the date of the agreement and 3 days before the start of the term loan, a fixed rate for the amount outstanding under the credit facility. Our ability to select the fixed rate option is subject to several conditions, all of which are set out in the loan agreement.

The interest rate on our bank debt was 2.28 percent at June 30, 2003 and July 23, 2003. At our election, any portion of our outstanding bank debt may be fixed at the Libor Rate, as adjusted depending on the level of our debt as a percentage of the amount available for us to borrow. The Libor Rate may be fixed for periods of up to 30, 60, 90 or 180 days with the balance of our bank debt being subject to the Prime Rate. During any Libor Rate funding period, we may not pay any part of the outstanding principal balance which is subject to the Libor Rate. Borrowings subject to the Libor Rate were $19.0 million at June 30, 2003 and July 23, 2003.

The loan agreement also requires us to maintain:

- consolidated net worth of at least $125 million;

- a current ratio of not less than 1 to 1;
- a ratio of long-term debt, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.2 to 1;
- a ratio of total liabilities, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.65 to 1; and
- working capital provided by operations, as defined in the loan agreement, cannot be less than $40 million in any year.

We are restricted from paying dividends (other than stock dividends) during any fiscal year in excess of 25 percent of our consolidated net income from the preceding fiscal year and we can pay dividends only if our working capital provided from our operations during the preceding year is equal to or greater than 175 percent of current maturities of long-term debt at the end of the preceding year. We also cannot incur additional debt except in 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 is prohibited unless it is in favor of our banks.

Contractual Commitments. We have the following contractual obligations at June 30, 2003:

	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)	$ 19,000	$ -	$ 6,861	$ 12,139	$ -
Retirement Agreement(2)	1,444	300	600	544	-
Operating Leases(3)	3,999	748	1,439	1,123	689
Total Contractual Obligations	$ 24,443	$ 1,048	$ 8,900	$ 13,806	$ 689

----

(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses 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.

(3) We lease office space in Tulsa and Woodward Oklahoma and Houston and Booker Texas under the terms of operating leases expiring through January 31, 2010 along with leasing space on short term commitments to stack excess rig equipment and production inventory. In the first quarter of 2003, we renegotiated our rental agreement for the Tulsa office reducing the price per square foot while adding additional space and lengthening the term of the agreement to January 31, 2010.

At June 30, 2003, we also have 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)	$ 1,603	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,781	$ 135	Unknown	Unknown	Unknown
Plugging Liability(3)	$ 11,287	$ 301	$ 2,047	$ 662	$ 8,277
Gas Balancing Liability(4)	$ 1,020	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations(5)	Unknown	Unknown	Unknown	Unknown	Unknown

(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.

(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 on certain properties where we believe there is insufficient 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 2003, 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 each year. These partnership agreements require, upon 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 percent of the units outstanding. We made repurchases of $1,000 in 2002 for such limited partners' interests. We made repurchases for $17,000 in the second quarter of 2003.

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 quarter of 2003, we entered into two natural gas collar contracts for approximately 37 percent of our April thru September 2003 production. One contract has a floor price of $4.00 and a ceiling price of $5.75 and the other contract has a floor price of $4.50 and a ceiling price of $6.02. During the first quarter of 2003, we also entered into two oil collar contracts for approximately 26 percent of our May thru December 2003 oil production. One contract has a floor price of $25.00 and a ceiling price of $32.20 and the other contact has a floor price of $26.00 and a ceiling price of $31.40. We had a $6,000 reduction in natural gas revenues as a result of the natural gas hedges settled in the second quarter of 2003. The fair value of the collar contracts still outstanding was recognized on the

June 30, 2003 balance sheet as a derivative liability of $119,000 and as a $74,000 loss, net of tax, in accumulated other comprehensive income. These hedges were fully effective. We did not have any hedging contracts in place in the first six months of 2002.

Self-Insurance. Unit is self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. Given the tightening in the insurance market our self-insurance levels have significantly increased. Effective August 1, 2002, our exposure (i.e. our deductible or retention), per occurrence, ranges from $200,000 for general liability to $1 million for 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 such coverage will adequately protect us against liability from all potential consequences.

Our Oil and Natural Gas Operations. Natural gas comprises 91 percent 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.

Based on our 2003 first six month production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $152,000 per month ($1,824,000 annualized) change in our pre-tax cash flow. Our first six month 2003 average natural gas price was $5.34 compared to an average natural gas price of $2.53 received in the first six months of 2002. We sell most of our natural gas production to third parties under month-to-month contracts. A $1.00 per barrel change in our oil price would have a $37,000 per month ($444,000 annualized) change in our pre-tax cash flow. Our first six months 2003 average oil price was $27.86 compared with an average oil price of $19.83 received in the first six months of 2002.

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. Also, price declines can adversely affect the semi-annual determination of the amount available for us to borrow under our bank loan 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.

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 acceptable financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when to incur these costs. We drilled 62 wells in the first six months of 2003 compared to 33 wells in the first six months of 2002. Through the first six months of 2003 we incurred $29.4 million of the $70 to $75 million in capital expenditures we expect to make for exploration, development drilling and acquisition of oil and natural gas properties in 2003. Based on current oil and natural gas prices, we plan to drill and or participate in an estimated 140 to 150 wells in 2003.

Contract Drilling. Our drilling work is subject to many factors that influence the number of rigs we have working as well as the costs and revenues associated with such work. These factors include 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. We have not encountered major difficulty in hiring and keeping rig crews, but such shortages have occurred periodically in the past. If demand for drilling rigs continues to increase we may well incur, shortages of experienced personnel which would limit our ability to increase the number of rigs we could operate. Through the first six months of 2003 we incurred $9.1 million in capital expenditures for our drilling operation. For the year 2003, we anticipate spending approximately $30 million on our drilling operations.

Low oil and natural gas prices during most of the 1980's and 1990's reduced demand for domestic land contract drilling rigs. However, in the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a big increase in demand for our rigs. Demand continued to increase until the end of the third quarter of 2001 and reached a high when 52 of our rigs were working in July 2001. Because of declining natural gas prices throughout 2001, demand for our rigs dropped significantly in the fourth quarter of 2001 and carried over into the first quarter of 2002. Average use of our rigs in the first six months of 2002 was 33.0 rigs compared with 56.8 rigs for the first six months of 2003. Natural gas prices began increasing in the fourth quarter of 2002 and they increased substantially in the first quarter of 2003. The increase in commodity prices along with our acquisition of 20 rigs in the third quarter of 2002, caused the rise in 2003 utilization.

As demand for our rigs increased during 2001 so did the dayrates we received. Our average dayrate reached $11,142 by September of 2001. However, as demand began to decrease, so did our rates. Our average dayrate in the first six months of 2002 was $8,055 and our average dayrate for the first six months of 2003 was $7,476. Increases in dayrates typically lag behind increases in utilization. We saw dayrates start to improve in the second quarter of 2003 and we think they will continue a gradual increase into the third quarter of 2003. Based on the average utilization of our rigs in the first six months of 2003, a $100 per day change in dayrates has a $5,700 per day ($2,081,000 annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties. The profit received by our contract drilling segment of $542,000 and $702,000 in the first six months of 2002 and 2003, 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.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for ten oil and natural gas partnerships which were formed privately and publicly. The partnership's revenues and costs are shared under formulas prescribed in each 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 2002, the total paid to us for all of these fees was approximately $232,000 per quarter and during the first six months of 2003 the amount paid has been 8 percent above last years quarterly average. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation were at least a specified amount ($22,680 for 2002 and 2003) and to the directors of Unit. The general partner of each of these partnerships is Unit Petroleum Company. Each employee partnership is named the Unit (year) Employee Oil and Gas Limited Partnership. The interests in these programs issued to the directors and named executive officers of Unit are disclosed in our proxy statements for each year's annual meeting of shareholders.

At June 30, 2003, we owned a 40 percent equity interest in Superior Pipeline Company, a natural gas gathering and processing company. Our investment including our share of the equity in the earnings of this company totaled $2.3 million at June 30, 2003. From time to time we may guarantee the debt of this company. However, as of June 30, 2003 and July 23, 2003, we were not guaranteeing any of the debt of this company.

On June 25, 2003, we acquired a 26.04 percent interest in Eagle Energy Partners I, L.P., ("Eagle") a Texas limited partnership for $2.5 million. Unit's percentage interest in the partnership is subject to change. During the next six months, Eagle will be attempting to acquire $2 million of additional capital from other investors. This newly formed partnership is engaged in the purchase and sale of natural gas, electricity (or similar electricity based products), or any future commodities, and the performance of scheduling and nomination services for energy related commodities and similar energy management functions. In addition to our investment in this partnership, the partnership has the right, subject to being the successful bidder, to buy, each month, a certain percentage of our natural gas during the six month period starting August 1, 2003. For August 2003, Eagle will buy approximately 26% of the natural gas we sell on a monthly basis for ourselves and other working interest owners.

Outlook. Both of our operating segments are extremely dependent on natural gas prices. These prices affect not only our production revenues, but also the demand and rates for our contract drilling services. Over the first six months of 2003 our average natural gas price received for each month excluding hedging ranged from $4.18 in January to a high of $8.38 in March and the average Nymex Henry Hub daily price for the same time period ranged from $4.55 to $6.72. On our second quarter earnings release date of July 23, 2003, the Nymex Henry Hub average contract settle price for the next twelve months was $4.96 and, we anticipate that if natural gas prices continue at that level, there will be increased demand for our rigs and upward movement on the rates we receive for our contract drilling services.

Critical Accounting Policies. We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized. At the end of each quarter, the net capitalized costs of our oil and natural gas properties is limited to the lower of unamortized cost or a ceiling. The ceiling is defined as the sum of the present value (10 percent discount rate) of estimated future net revenues from proved reserves, based on period-end oil and natural gas prices, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are subject to a write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts stockholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down cannot be reversed even if prices subsequently recover.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have large downward revisions in our estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil and natural gas prices in effect on June 30, 2003 ($5.00 per Mcf for natural gas and $28.44 per barrel for oil), the unamortized cost of our domestic oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas prices remain erratic and any significant declines below quarter-end prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

The value of our oil and natural gas reserves is used to determine most of the loan value under our loan agreement. This value is affected by both price changes and the measurement of reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimate of oil and natural gas reserves require extensive judgments of our reservoir engineering data and are less precise than other estimates made in connection with financial disclosures. Assigning monetary values to our estimates does not reduce the subjectivity and changing nature of our reserve estimates. Indeed, the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves.

We use the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the natural gas balancing position on wells in which we have an imbalance are not material.

Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and betterments are capitalized while repairs and maintenance are expensed. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances suggest the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause us to reduce the carrying value of our property and equipment.

Because the Company does not bear the risk of completion of wells drilled under "daywork" drilling contracts, it recognizes revenues and expenses generated from those contracts as the services are performed (i.e. daily). Under "footage" and "turnkey" contracts, revenues and expenses are recognized when the company has satisfied certain requirements as detailed in the applicable contracts. If it has been determined that a well is going to incur a loss, the entire amount of the estimated loss is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time terms of the contract are completed. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (FAS 142) were issued by the Financial Accounting Standards Board (FASB) in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the disclosures required by FAS 141 and 142 relative to intangibles would be included in the notes to financial statements. Historically, we, like many other oil and gas companies, have included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after FAS 141 and 142 became effective.

Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with full cost accounting rules.

At June 30, 2003, we had undeveloped leaseholds of approximately $15,811,000 that would be classified on our balance sheet as “intangible undeveloped leasehold” and developed leaseholds of an estimated $20,163,000 that would be classified as “intangible developed leasehold” if we applied the interpretations. This classification would require us to make disclosures set forth under FAS 142 related to these interests.

We will continue to classify our oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

Acquisitions. On August 14, 2003 Unit signed a definitive agreement with PetroCorp Incorporated (AMEX - PEX) to acquire all the outstanding shares of PetroCorp. The purchase price under the agreement is approximately $182,000,000 and will be paid all in cash. The purchase price is subject to certain adjustments including $6,500,000 which will be place in escrow to settle or satisfy certain contingent tax and litigation liabilities if not resolved prior to closing. Consummation of the transaction is subject to several conditions typical of transactions of this nature including regulatory review and the approval by two-thirds of PetroCorp's shareholders. PetroCorp shareholders representing approximately 50% of the outstanding shares of PetroCorp have agreed to support the merger. PetroCorp is a Tulsa-based company that explores and develops oil and natural gas properties primarily in Texas and Oklahoma.

Change in Board of Directors and Officers. On June 18, 2003 we announced that King Kirchner, an original founder of Unit Corporation, will retire as Chairman of the Board of Directors of Unit Corporation effective August 1, 2003. Mr. Kirchner will remain on the Board. Effective with Mr. Kirchner's retirement, our Board of Directors elected John G. Nikkel to succeed Mr. Kirchner as Chairman of the Board of Directors. Mr. Nikkel will continue to serve as the Company's Chief Executive Officer. Mr. Nikkel served as our President for almost 20 years and has served as our Chief Executive Officer since July of 1999. Effective August 1, 2003, Mr. Larry Pinkston, our current Executive Vice President will assume the office of President in addition to his current role as Treasurer and Chief Financial Officer. Mr. Pinkston has been employed by us for 22 years.

SAFE HARBOR STATEMENT

Statements in this document as well as information contained in written material, press releases and oral statements issued by or for us contain, or may contain, certain "forward-looking statements" within the meaning of federal securities laws. All statements, other than statements of historical facts, included in this document which address activities, events or developments which we expect or expect will or may occur in the future are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" and similar expressions are also intended to identify forward-looking statements. These forward-looking statements include, among others, such things as:

- the amount and nature of future capital expenses;
- wells to be drilled or reworked;
- oil and natural gas prices to be received and demand for oil and natural gas;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of our oil and natural gas reserves;
- expansion and growth of our business and operations;
- availability of drilling rigs and rig related equipment;
- drilling rig use, revenues and costs; and
- availability of qualified labor.

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

- the risk factors discussed in this document;
- general economic, market or business conditions;
- the nature or lack of business opportunities that may be presented to and pursued by us;
- demand for land drilling services;
- changes in laws or regulations; and
- other reasons, most of which are beyond our control.

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

Second Quarter 2003 versus Second Quarter 2002

Provided below is a comparison of selected operating and financial data for the second quarter of 2003 verses the second quarter of 2002:

	Second Quarter 2002	Second Quarter 2003	Percent Change
Total Revenue	$ 44,753,000	$ 72,980,000	63%
Net Income	$ 5,108,000	$ 11,691,000	129%
Oil and Natural Gas:			
Revenue	$ 18,668,000	$ 26,871,000	44%
Average natural gas price (Mcf)	$ 3.00	$ 4.74	58%
Average oil price (Bbl)	$ 22.59	$ 25.51	13%
Natural gas production (Mcf)	5,097,000	4,955,000	(3%)
Oil production (Bbl)	110,000	123,000	12%
Operating profit (revenue less operating costs)	$ 13,507,000	$ 20,978,000	55%
Operating margin	72%	78%	
Depreciation, depletion and amortization rate (Mcfe)	$ 1.03	$ 1.12	8%
Depreciation, depletion and amortization	$ 5,988,000	$ 6,445,000	8%
Drilling:			
Revenue	$ 25,841,000	$ 45,221,000	75%
Percentage of revenue from daywork contracts	85%	97%	
Average number of rigs in use	33.2	62.4	88%
Average dayrate on daywork contracts	$ 7,698	$ 7,601	(1%)
Operating profit (revenue less operating costs)	$ 5,704,000	$ 11,580,000	(11%)
Operating margin	22%	26%	
Depreciation	$ 2,928,000	$ 5,899,000	101%
General and Administrative Expense	$ 2,013,000	$ 2,070,000	3%
Interest Expense	$ 229,000	$ 175,000	(24%)
Average Interest Rate	3.00%	2.17%	(28%)
Average Long-Term Debt Outstanding	$ 23,470,000	$ 22,968,000	(2%)

Oil and natural gas revenues, operating profits and operating profit margins were all positively affected by higher oil and natural gas prices and increased oil production between the second quarter of 2003 and the second quarter of 2002. We continue to focus our drilling program on the development of natural gas reserves, but natural gas production was down between the comparative quarters due to delays in placing new natural gas production on line early in the year and production from older wells declined. Total operating cost increased in the second quarter of 2003 when compared with the second quarter of 2002 due mainly to higher gross production taxes which are based on a percentage of revenues which were generated by higher commodity prices. Our total depreciation, depletion and amortization ("DD&A) increased due an increase in our DD&A rate per Mcfe. During 2002 and continuing into the first half of 2003, we experienced higher cost per Mcfe for the discovery of new reserves through our development drilling program resulting in an increase in the DD&A rate between the comparative quarters.

Reduced natural gas prices in the fourth quarter of 2001 and the first half of 2002, caused decreases in operator demand for contract drilling rigs within our working area throughout most of 2002. Natural gas prices increased once again into the first quarter of 2003 and along with the acquisition of 20 rigs in the third quarter of 2002 our second quarter 2003 utilization recovered and was 88 percent higher than the second quarter of 2002. In the second quarter of 2003 dayrates for our rigs also increased from our first quarter lows and were only one percent lower than in the second quarter of 2002. Operating margins increased between the comparative periods, since we had higher rig utilization to cover our fixed operating costs. Approximately 3 percent of our total drilling revenues in the second quarter of 2003 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002 and the increase in rigs used between the comparative quarters.

General and administrative expense was higher in the first quarter of 2003 due to increases in insurance expense. Our total interest expense is lower due to lower interest rates and decreased average debt outstanding. Income tax expense increased primarily due to the increase in income from continuing operations.

Six Months 2003 versus Six Months 2002

Provided below is a comparison of selected operating and financial data for the first six months of 2003 verses the first six months of 2002:

	First Six Months 2002	First Six Months 2003	Percent Change
Total Revenue	$ 83,483,000	$ 141,426,000	69%
Income Before Change in Accounting Principle	$ 7,750,000	$ 24,350,000	214%
Net Income	$ 7,750,000	$ 25,675,000	231%
Oil and Natural Gas:			
Revenue	$ 30,629,000	$ 60,119,000	96%
Average natural gas price (Mcf)	$ 2.53	$ 5.34	111%
Average oil price (Bbl)	$ 19.83	$ 27.86	40%
Natural gas production (Mcf)	9,653,000	9,810,000	2%
Oil production (Bbl)	227,000	238,000	5%
Operating profit (revenue less operating costs)	$ 20,520,000	$ 47,611,000	280%
Operating margin	67%	79%	
Depreciation, depletion and amortization rate (Mcfe)	$ 1.01	$ 1.10	9%
Depreciation, depletion and amortization	$ 11,257,000	$ 12,492,000	11%
Drilling:			
Revenue	$ 52,555,000	$ 79,787,000	52%
Percentage of revenue from daywork contracts	91%	96%	
Average number of rigs in use	33.0	56.8	72%
Average dayrate on daywork contracts	$ 8,055	$ 7,476	(7%)
Operating profit (revenue less operating costs)	$ 13,286,000	$ 18,335,000	38%
Operating margin	25%	23%	
Depreciation	$ 5,739,000	$ 10,793,000	88%
General and Administrative Expense	$ 4,042,000	$ 4,520,000	12%
Interest Expense	$ 516,000	$ 386,000	(25%)
Average Interest Rate	3.00%	2.13%	(29%)

Average Long-Term Debt Outstanding	$ 26,075,000	$ 27,266,000	5%

Oil and natural gas revenues, operating profits and operating profit margins were all positively affected by higher prices received for both oil and natural gas between the first six months of 2003 and the first six months of 2002. We continue to focus our drilling program on the development of natural gas reserves and we experienced an increase in both our oil and natural gas production volumes between the comparative six month periods. Total operating cost increased in the first six months of 2003 when compared with the first six months of 2002 due mainly to higher gross production taxes which are based on a percentage of revenues which were generated by higher commodity prices and to a lesser extent from increased costs associated with adding personnel to support the growth in this segment of our business. Our total depreciation, depletion and amortization ("DD&A) increased due to the increase in equivalent volumes produced and an increase in our DD&A rate per Mcfe. During 2002 and into the first six months of 2003, we experienced higher cost per Mcfe for the discovery of new reserves through our development drilling program resulting in an increase in the DD&A rate between the comparative six month periods.

Reduced natural gas prices in the fourth quarter of 2001 and the first half of 2002, caused decreases in operator demand for contract drilling rigs within our working area throughout most of 2002. Demand recovered in the first half of 2003 and the average number of rigs in use was 24 more than during the first six months of 2002. We also had more rigs available due to the 20 rig acquisition we completed in August of 2002. Since utilization typically increases before dayrates our dayrates did not start to improve until the second quarter of 2003, so the average dayrate for the first six months of 2003 was lower than the average dayrate received for the same period in 2002. As a result, operating margins declined between the comparative periods. Approximately four percent of our total drilling revenues in the first six months of 2003 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. Nine percent of our total drilling revenues came from footage and turnkey contracts in the first six months of 2002. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002 and the increase in rigs used between the comparative quarters.

General and administrative expense was higher in the first six months of 2003 due to increases in insurance expense. Our total interest expense is lower due to lower interest rates and was partially offset by an increase in average debt outstanding. Income tax expense increased primarily due to the increase in income from continuing operations.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our operations are exposed to market risks due to changes in commodity prices. 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 have received for our oil and natural gas production have been volatile and such volatility is expected to continue.

In an effort to try and reduce the impact of price fluctuations, over the past several years we periodically have 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 under Item 2.

Item 4. Controls and Procedures

Within the 90 days prior to the date of 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 pursuant to Exchange Act Rule 13a-14. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic SEC filings relating to the company (including its consolidated subsidiaries).

There were no significant 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. Changes in 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

On May 7, 2003 we held our Annual Meeting of Stockholders. At the meeting the following matters were voted on, with each receiving the votes indicated:

I. Election of Nominees John G. Nikkel and John S. Zink to serve as directors.

Nominee	Numbers of Votes For	Against or Withheld
John G. Nikkel	39,352,332	186,334
John S. Zink	39,338,361	200,305

The following directors, whose term of office did not expire at the annual meeting, continue as directors of the Company: Earle Lamborn, William B. Morgan, John H. Williams, King P. Kirchner, Don Cook and J. Michael Adcock.

II. Ratification of the appointment of PricewaterhouseCoopers L L P as the Company's independent certified public accountants for the fiscal year 2003.

For	-	38,930,857
Against	-	592,482
Abstain	-	15,327

Item 5. Other Information

In accordance with Section 10A(i)(2) of the Securities Exchange Act of 1934, as added by Section 202 of the Sarbanes-Oxley Act of 2002, we are responsible for disclosing any non-audit services approved by our Audit Committee (the "Committee") to be performed by PricewaterhouseCoopers LLP, who is our external auditor. Non-audit services are defined in the Act as services other than those provided in connection with an audit or a review of the financial statements of Unit. The Committee has approved the engagement of PricewaterhouseCoopers LLP to provide non-audit services assisting in (i) reviewing our internal control procedures, (ii)our pending acquisition of PetroCorp Incorporated and (iii) responding to the SEC's comments in connection with the SEC's review of the recent S-3 Registration Statement we filed on March 31, 2003.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

15	Letter re: Unaudited Interim Financial Information.
31.1	SEC Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by the Principal Executive Officer, John G. Nikkel of Unit Corporation.
31.2	SEC Certification Pursuant to Section 906 of the Sarbanex-Oxley Act of 2002 by the Principal Financial Officer, Larry D. Pinkston, of Unit Corporation.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) On April 23, 2003, we filed a report on Form 8-K under Item 7 and 9. This report furnished as an exhibit the press release announcing our results of operations and financial condition for the quarter ended March 31, 2003.

On July 1, 2003, we filed a report on Form 8-K under Item 5 and 7. This report announced that we had entered into a letter of intent to acquire PetroCorp Incorporated (“PetroCorp”) (AMEX:PEX) and furnished as an exhibit the press release of the announcement.

SIGNATURES

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

UNIT CORPORATION

Date: August 14, 2003

By: /s/ John G. Nikkel

JOHN G. NIKKEL
Chairman of the Board,
Chief Executive Officer,
Chief Operating Officer
and Director

Date: August 14, 2003

By: /s/ Larry D. Pinkston

LARRY D. PINKSTON
President, Chief
Financial Officer
and Treasurer

Exhibit 15

August 14, 2003

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

RE: Unit Corporation

Registration on Form S-8 and S-3

We are aware that our report dated July 23, 2003 on our review of interim financial information of Unit Corporation for the three and six month periods ended June 30, 2003 and 2002 and included in the Company's Form 10-Q for the quarter ended June 30, 2003 is incorporated by reference in the Company's 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).

PricewaterhouseCoopers L L P

Exhibit 31.1

CERTIFICATIONS

I, John G. Nikkel, 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 quarterly 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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 the 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 affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers 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 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: August 14, 2003

By: /s/ John G. Nikkel

JOHN G. NIKKEL
Chairman of the Board,

Chief Executive Officer,
Chief Operating Officer
and Director

Exhibit 31.2

CERTIFICATIONS

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 quarterly 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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 the 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 affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers 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 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: August 14, 2003

By: /s/ Larry D. Pinkston

LARRY D. PINKSTON

President, 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 June 30, 2003 (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 June 30, 2003 and December 31, 2002 and for the three months and six months ended June 30, 2003 and 2002.

Dated: August 14, 2003

By: /s/ John G. Nikkel

____

John G. Nikkel
CHIEF EXECUTIVE OFFICER

Dated: August 14, 2003

By: /s/ Larry D. Pinkston

____

Larry D. Pinkston
President and Chief Financial Officer
(PRINCIPAL ACCOUNTING OFFICER)

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 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.