SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

[x] QUARTERLY REPORT PURSUANT TO SECTION13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2004
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	45,731,999
Class	Outstanding at July 29, 2004

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

	December 31, 2003	June 30, 2004 (Unaudited)
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 598	$ 5,779
Restricted cash	--	5,265
Accounts receivable	58,807	67,050
Materials and supplies	8,023	12,247
Other	5,314	5,240
Total current assets	72,742	95,581
Property and Equipment:		
Drilling equipment	424,321	450,617
Oil and natural gas properties, on the full cost method:		
Proved properties	528,110	679,940
Undeveloped leasehold not being amortized	17,486	26,248
Transportation equipment	9,828	10,852
Other	14,535	16,556

	994,280	1,184,213
Less accumulated depreciation, depletion, amortization and impairment	385,219	422,772
Net property and equipment	609,061	761,441
Goodwill	23,722	23,722
Other Assets	7,400	8,743
Total Assets	$ 712,925	$ 889,487

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS - CONTINUED

	December 31, 2003	June 30, 2004 (Unaudited)
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term liabilities and debt	$ 1,015	$ 949
Accounts payable	32,871	37,363
Accrued liabilities	17,925	30,299
Total current liabilities	51,811	68,611
Long-Term Debt	400	70,000
Other Long-Term Liabilities	17,893	24,146
Deferred Income Taxes	127,053	173,616
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, 45,592,012 and 45,730,568 shares issued, respectively	9,117	9,145
Capital in excess of par value	307,938	309,695
Accumulated other comprehensive income	--	(131)
Retained earnings	198,713	234,405
Total shareholders' equity	515,768	553,114
Total Liabilities and Shareholders' Equity	$ 712,925	$ 889,487

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF INCOME (UNAUDITED)(NOTE 1)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2004	2003	2004
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 45,221	$ 67,110	$ 79,787	$ 130,324
Oil and natural gas	26,871	46,334	60,119	84,324
Other	572	999	1,317	1,695
Total revenues	72,664	114,443	141,223	216,343
Expenses:				
Contract drilling:				
Operating costs	33,641	48,364	61,452	94,920
Depreciation	5,899	7,754	10,793	15,218
Oil and natural gas:				
Operating costs	5,893	10,662	12,508	20,394
Depreciation depletion and amortization	6,445	11,535	12,492	21,712
General and administrative	2,070	3,103	4,520	5,874
Other	209	290	529	512
Interest	175	514	386	931
Total expenses	54,332	82,222	102,680	159,561
Income Before Income Taxes	18,332	32,221	38,543	56,782
Income Tax Expense:				
Current	144	1,556	299	2,127
Deferred	6,824	10,751	14,350	19,514
Total income taxes	6,968	12,307	14,649	21,641
Equity in Earnings of Unconsolidated Investments, Net of Income Tax	327	270	456	550
Income Before Change in Accounting Principle	11,691	20,184	24,350	35,691
Cumulative Effect of Change in Accounting Principle (Net of Income Tax of $811)	--	--	1,325	--

Net Income	$ 11,691	$ 20,184	$ 25,675	$ 35,691
Basic Earnings per Common Share:				
Income before change in accounting principle	$ 0.27	$ 0.44	$ 0.56	$ 0.78
Cumulative effect of change in accounting principle, net of income tax	--	--	0.03	--
Net income	$ 0.27	$ 0.44	$ 0.59	$ 0.78
Diluted Earnings per Common Share:				
Income before change in accounting principle	$ 0.27	$ 0.44	$ 0.56	$ 0.78
Cumulative effect of change in accounting principle, net of income tax	--	--	0.03	--
Net income	$ 0.27	$ 0.44	$ 0.59	$ 0.78

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

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

	Six Months Ended June 30,	
	2003	2004
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 25,675	$ 35,691
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion, and amortization	23,621	37,446
Deferred tax expense	14,626	19,851
Other	(372)	(139)
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(13,788)	416
Accounts payable	3,417	(1,335)
Material and supplies	1,611	(4,224)
Prepaid expenses	3,748	(19)
Contract advances	2,271	1,091
Other - net	(154)	5,396
Net cash provided by operating activities	60,655	94,174
Cash Flows From (Used In) Investing Activities:		
Capital expenditures (including producing property acquisitions)	(42,104)	(167,620)
Proceeds from disposition of assets	520	1,475
Other-net	(2,498)	1,735
Net cash used in investing activities	(44,082)	(164,410)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(11,500)	69,600
Net payments of notes payable and other long-term debt	(1,020)	(33)
Proceeds from exercise of stock options	423	380

Book overdrafts	(3,647)	5,470
Net cash from (used in) financing activities	(15,744)	75,417
Net Increase in Cash and Cash Equivalents	829	5,181
Cash and Cash Equivalents, Beginning of Year	497	598
Cash and Cash Equivalents, End of Period	$ 1,326	$ 5,779

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,	
	2003	2004	2003	2004
	(In thousands)			
Net Income	$ 11,691	$ 20,184	$ 25,675	$ 35,691
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	(233)	(252)	(78)	(556)
Adjustment reclassification - derivative settlements	4	347	4	425
Comprehensive Income	$ 11,462	$ 20,279	$ 25,601	$ 35,560

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

NOTE 1 - BASIS OF 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 and six months ended June 30, 2004 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, 2003. The company's independent auditors performed a review of these interim financial statements in accordance with the 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 auditor'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 June 30,		Six Months Ended June 30,	
	2003	2004	2003	2004
	(In thousands except per share amounts)			
Net Income, as Reported	$ 11,691	$ 20,184	$ 25,675	$ 35,691
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax	168	219	335	438
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(471)	(627)	(875)	(1,140)
Pro Forma Net Income	$ 11,388	$ 19,776	$ 25,135	$ 34,989
Basic Earnings per Share:				
As reported	$ 0.27	$ 0.44	$ 0.59	$ 0.78
Pro forma	$ 0.26	$ 0.43	$ 0.58	$ 0.77
Diluted Earnings per				

Share:				
As reported	$ 0.27	$ 0.44	$ 0.59	$ 0.78
Pro forma	$ 0.26	$ 0.43	$ 0.58	$ 0.76

The fair value of each option granted is estimated using the Black-Scholes model. There were no options granted in the first quarter of 2003 and 2004. In the second quarter of 2003 and 2004 options were granted of 21,000 and 31,500 shares, respectively with an estimated fair value of approximately $262,000 and $538,000, respectively. For options granted in the second quarter of 2003 and 2004, the company's estimate of stock volatility was 0.53 and 0.52, respectively, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 3.6% in the second quarter of 2003 and 4.7% in the second quarter of 2004. 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.

	Net Income (Numerator)	Weighted Average Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Three Months Ended June 30, 2003:			
Basic earnings per common share	$ 11,691	43,521	$ 0.27
Effect of dilutive stock options	--	228	
Diluted earnings per common share	$ 11,691	43,749	$ 0.27
For the Three Months Ended June 30, 2004:			
Basic earnings per common share	$ 20,184	45,723	$ 0.44
Effect of dilutive stock options	--	208	
Diluted earnings per common share	$ 20,184	45,931	$ 0.44

All options and their average exercise prices for the three month periods ended June 30, 2003 and 2004 were included in the computation of diluted earnings per share.

	Net Income (Numerator)	Weighted Average Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Six Months Ended June 30, 2003:			
Basic earnings per common share:			
Income before change in accounting principle	$ 24,350	43,477	$ 0.56

Cumulative effect of change in accounting principle net of income tax	1,325	43,477	0.03
Net Income	$ 25,675	43,477	$ 0.59
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		43,477	
Effect of dilutive stock options		213	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		43,690	
Income before change in accounting principle	$ 24,350	43,690	$ 0.56
Cumulative effect of change in accounting principle net of income tax	1,325	43,690	0.03
Net Income	$ 25,675	43,690	$ 0.59

	Net Income (Numerator)	Weighted Average Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Six Months Ended June 30, 2004:			
Basic earnings per common share:			
Income before change in accounting principle	$ 35,691	45,697	$ 0.78
Net Income	$ 35,691	45,697	$ 0.78
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		45,697	
Effect of dilutive stock options		190	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		45,887	
Income before change in accounting principle	$ 35,691	45,887	$ 0.78
Net Income	$ 35,691	45,887	$ 0.78

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, 2003 and 2004 because the option exercise prices were greater than the average market price of common shares:

	2003	2004
Options	21,000	24,500
Average exercise price	$ 20.10	$ 28.23

NOTE 3 - ACQUISITIONS

On May 4, 2004, the company acquired two drilling rigs and related equipment for $5.5 million. The rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. The rigs are being added into our Rocky Mountain division and will be available in August and September of 2004.

On January 30, 2004, the company acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash ($92.2 million net of cash acquired). PetroCorp Incorporated explores and develops oil and natural gas properties primarily in Texas and Oklahoma. Approximately 84% of the oil and natural gas properties acquired in the acquisition are located in the Mid-Continent and Permian basins, while 6% are located in the Rocky Mountains and 10% are located in the Gulf Coast basin. The acquired properties increased the company's oil and natural gas reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide additional locations for future development drilling. The results of operations for this acquired company are included in the statement of income for the period subsequent to January 30, 2004.

The amount paid for PetroCorp was allocated as follows (in thousands):

Working Capital	$ 97,051
Undeveloped Oil and Natural Gas Properties	6,321
Proved Oil and Natural Gas Properties	108,984
Property and Equipment - Other	382
Other Assets	1,445
Other Long-Term Liabilities	(5,271)
Deferred Income Taxes (net)	(26,792)
Total consideration	$ 182,120

The amount paid was determined through arms-length negotiations between the parties and only the cash portion of the transaction appears in the investing and financing activities sections of the company's consolidated condensed financial statements of cash flows.

At the closing of this acquisition, $5.5 million, otherwise payable to the shareholders of PetroCorp Incorporated, was transferred to an escrow account to reserve for certain liabilities and related costs that may be incurred by PetroCorp Incorporated after the closing of the acquisition. As of June 30, 2004, $5.3 million remained in escrow and is reflected as restricted cash.

Unaudited summary pro forma results of operations for the company, reflecting the above acquisition as if it occurred at January 1, 2003 are as follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2004	2003	2004
	(In thousands except per share amounts)			
Revenues	$ 85,098	$ 114,443	$ 164,091	$ 219,523
Income Before Change In Accounting Principle	$ 15,244	$ 20,184	$ 30,489	$ 36,253
Net Income	$ 15,244	$ 20,184	$ 28,845	$ 36,253

Diluted Earnings per Share:				
Income before change in accounting principle	$ 0.35	$ 0.44	$ 0.70	$ 0.79
Net income	$ 0.35	$ 0.44	$ 0.66	$ 0.79

The pro forma results of operations are not necessarily indicative of the actual results of operations that would have occurred had the purchase actually been made at the beginning of the respective periods nor of the results which may occur in the future.

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 million for each of the three years following the acquisition. The assets of SerDrilco Incorporated included 12 drilling rigs, spare drilling equipment, a fleet of 12 larger trucks and trailers, various other vehicles and a district office and equipment yard in and near Borger, Texas. The results of operations for the acquired entity are included in the statement of income for the periods after December 7, 2003.

The amount paid in this acquisition was determined based on the depth capacity of the rigs, the working condition of the rigs and the ability of the rigs to enhance the company's ability to provide services and equipment required by its customers on a timely basis within the Anadarko Basin of Western Oklahoma and the Texas Panhandle. The company acquired SerDrilco Incorporated's tax basis in the assets acquired resulting in the recording of a deferred tax liability and goodwill of $10.9 million. The allocation of the amount paid and goodwill recognized for the acquisition is as follows (in thousands):

Allocation of Total Consideration Paid and Goodwill Recognized:	
Drilling rigs including tubulars	$ 31,012
Spare drilling equipment	904
Office, yard & yard equipment	1,200
Trucking fleet	1,486
Other vehicles	398
Total cash consideration	35,000
Goodwill recognized	10,928
Total consideration paid and recognized	$ 45,928

NOTE 4 - CREDIT AGREEMENT

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. At June 30, 2004, the company had elected a commitment amount of only $100 million in order to reduce financing costs. 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 at the inception of the new agreement, $40,000 of which will be paid annually and the remainder of the fees will be amortized over the 4 year life of the loan. At June 30, 2004 the company had $70.0 million borrowed all of which was subject to the Eurodollar Rate. The average interest rate for the first six months of 2004 was 2.20%.

The borrowing base under the current credit facility is re-determined twice each year on May 10 and November 10. This 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 Eurodollar Rate for a 30, 60, 90 or 180 day term. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar 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 Eurodollar Rate is computed at the Eurodollar 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 Eurodollar 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 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 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 credit agreement) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On June 30, 2004 the company was in compliance with the covenants of its credit agreement.

NOTE 5 - NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2003 the company 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. The company 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). The company does not have any assets restricted for the purpose of settling the plugging liabilities.

The following table shows the activity for the six months ending June 30, 2003 and 2004 relating to the company's retirement obligation for plugging liability:

	Six Months Ended	
	2003	2004
	(In Thousands)	
Short-Term Plugging Liability:		
Liability at beginning of period	$ 203	$ 303
Accretion of discount	8	5
Liability incurred in the period	53	--
Liability settled in the period	--	(62)
Sold	--	(21)
Reclassification of liability from long- to short-term	37	--
Plugging liability at end of period	$ 301	$ 225
Long-Term Plugging Liability:		
Liability at beginning of period	$ 10,632	$ 11,691
Accretion of discount	244	393
Liability incurred in the period	226	5,745
Liability settled in the period	(79)	(5)
Sold	--	(63)
Reclassification of liability from long- to short-term	(37)	--
Plugging liability at end of period	$ 10,986	$ 17,761

On January 17, 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB 51" ("FIN 46"). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support

from other parties. FIN 46, as amended, was effective for the company in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, primarily Eagle Energy Partnership I, L.P., did not have an impact on the company's financial position or results of operations or cash flows. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, FIN 46 and the amendment of FIN 46 were effective for the company, as amended, in the quarter ending March 31, 2004. The company evaluated FIN 46 and FIN 46(R) with regard to these types of entities in which it has an ownership interest and there was no material impact to the financial position, results of operations or cash flows from the adoption of FIN 46 and FIN 46(R).

NOTE 6 - 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 the company 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, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas 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 notes to the company's financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. The company, like many other oil and gas companies, has included oil and gas extraction rights as part of the oil and gas properties, even after FAS 141 and 142 became effective. The company's results of operations and cash flows would not be affected, since these oil and gas mineral extraction rights would continue to be amortized in accordance with full cost accounting rules.

The FASB has issued a proposed FASB Staff Position 142-b "Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities" (FSP 142-b) to address the application of FAS 141 to the oil and natural gas industry. If adopted as written, the proposed FSP 142-b would confirm the company's historical treatment of these costs. The company will continue to monitor the FASB's treatment of this issue.

NOTE 7 - HEDGING ACTIVITY

Periodically the company hedges the prices 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 cash flow.

During the first quarter of 2003, the company entered into two natural gas collar contracts. Each contract was for 10,000 MMBtu's of production per day and covered the period of April through September 2003. One contract had 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, the company also entered into two oil collar contracts. Each contract was for 5,000 barrels of production per month and covered the period of May through December 2003. One contract had a floor price of $25.00 and a ceiling price of $32.20 and the other contact had a floor price of $26.00 and a ceiling price of $31.40. The fair value of the collar contracts was recognized on the June 30, 2003 balance sheet as a derivative liability of $119,000 and at a loss of $74,000, net of tax, in accumulated other comprehensive income. These hedges were fully effective. Natural gas revenues were reduced by $6,000 in the second quarter of 2003 due to the settlement of the June natural gas collar contract.

During the first quarter of 2004, the company entered into a natural gas collar covering 10,000 MMBtu's per day of its natural gas production. The transaction covers the periods of April through October of 2004 and has a floor of $4.50 and a ceiling of $6.76. In the first quarter of 2004, the company also entered into an oil hedge covering 1,000 barrels per day of its oil production. The transaction covers the periods of February through December of 2004 and has an average price of $31.40. In April 2004, the company entered into a natural gas collar covering an additional 10,000 MMBtu's per day of its natural gas production. The transaction covers the periods of May through October of 2004 and has a floor of $5.00 and a ceiling of $7.00. The fair value of the collar contracts and the oil hedge was recognized on the June 30, 2004 balance sheet as a derivative liability of $211,000 and at a loss of $131,000, net of tax, in accumulated other comprehensive income. These hedges were fully effective. The natural gas collar contracts have not changed natural gas revenues during the first six months of 2004. Oil revenues were reduced by $561,000 in the second quarter of 2004 due to the settlement of the oil hedge and oil revenues have been reduced by $687,000 for the six months ended June 30, 2004.

NOTE 8 - COMMITMENTS AND CONTINGENCIES

Because of increasing cost of steel and the potential for limited availability of new drill pipe, in the first quarter of 2004 the company committed to purchase by the end of 2004 approximately 275,000 feet of drill pipe for $9.3 million. At June 30, 2004, 217,000 feet (or approximately $7.4 million) of this commitment remained outstanding.

NOTE 9 - INDUSTRY SEGMENT INFORMATION

The company has two primary 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.

Management 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, 2003 and 2004 is as follows:

	Three Months Ended June 30, 2003	Three Months Ended June 30, 2004	Six Months Ended June 30, 2003	Six Months Ended June 30, 2004
	(In thousands)			
Revenues:				
Contract drilling	$ 46,528	$ 70,581	$ 83,041	$ 136,161
Elimination of inter-segment revenue	1,307	3,471	3,254	5,837
Contract drilling net of inter-segment revenue	45,221	67,110	79,787	130,324
Oil and natural gas	26,871	46,334	60,119	84,324
Other	572	999	1,317	1,695
Total revenues	$ 72,664	$ 114,443	$ 141,223	$ 216,343
Operating Income (1):				
Contract drilling	$ 5,681	$ 10,992	$ 7,542	$ 20,186
Oil and natural gas	14,533	24,137	35,119	42,218
Total operating income	20,214	35,129	42,661	62,404
General and administrative expense	(2,070)	(3,103)	(4,520)	(5,874)
Interest expense	(175)	(514)	(386)	(931)
Other income - net	363	709	788	1,183
Income before income taxes	$ 18,332	$ 32,221	$ 38,543	$ 56,782

(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 10 - SUBSEQUENT EVENTS

On July 29, 2004, the company closed its acquisition of the 60% of Superior Pipeline Company LLC ("Superior") we did not own for $19.8 million, resulting in the company owning 100% of Superior. Superior is a mid-stream company engaged primarily in the gathering, processing and treating of natural gas and owns one natural gas treatment plant, two processing plants, 12 active gathering systems and 375 miles of pipeline. Superior operates in western Oklahoma and the Texas Panhandle and has been in business for 8 years. This acquisition will give the company additional alternatives for it to increase its ability to gather and market its natural gas and third party natural gas and construct or acquire existing natural gas gathering and processing facilities. In the third quarter of 2004, the company will fully consolidate Superior in its financial statements.

On July 30 ,2004, the company's wholly-owned subsidiary, Unit Drilling Company, closed its acquisition of Sauer Drilling Company, a Casper-based drilling company and a wholly-owned subsidiary of Tom Brown, Inc., for $34.7 million in cash paid at closing. An additional amount equal to Sauer's working capital will be determined and paid after closing. The amount of the working capital will be settled within 90 days of the closing of the agreement. The acquisition includes 9 drilling rigs, a fleet of trucks, and an equipment and repair yard with associated inventory, located in Casper, Wyoming. Of the 9 rigs, 8 are currently operating under contract in the Wind River Basin in Wyoming and the Paradox Basin in Colorado. 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 4 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 will increase the company's market share in the Rocky Mountains in the medium to smaller drilling rig depth ranges. The equipment yard, located in Casper, Wyoming, will continue to provide service space for the nine newly acquired rigs and trucks as well as for the company's existing Rocky Mountain rig fleet.

On August 2, 2004, Unit completed the sale of its investment in Eagle Energy Partners I LP for $6.2 million. In the third quarter of 2004, a gain before income taxes of $3.8 million will be recognized from this sale.

On July 15, 2004, the company increased its loan commitment from $100 million to $150 million. On August 4, 2004, the company's total borrowings under its credit agreement was $113 million.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of June 30, 2004, and the related condensed consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2004 and 2003 and the condensed consolidated statements of cash flows for the six-month periods ended June 30, 2004 and 2003. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

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

We previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2003, and the related consolidated statements of income, shareholder's equity and cash flows for the year then ended (not presented herein), and in our report dated February 18, 2004 we expressed an unqualified opinion on those consolidated financial statements in a report that also included an explanatory paragraph referring to a change in accounting principle discussed in Note 1 to the financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2003, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Tulsa, Oklahoma
August 4, 2004

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 generated from our two 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, the demand for and the dayrates we receive for our drilling rigs and, to a lesser extent, the prices we receive for our oil production.

At June 30, 2004, we had cash totaling $5.8 million and we had borrowed $70.0 million of the $100.0 million we had elected to have available under our credit agreement. As of July 15, 2004, we elected at that time to increase our credit commitment to $150 million. On August 4, 2004, after the acquisition of Superior Pipeline Company LLC, Sauer Drilling Company and the sale of our investment in Eagle Energy Partners I LP, our borrowings under our credit agreement were $113 million.

Our two principal business segments are (i) contract drilling carried out by our subsidiaries Unit Drilling Company, Service Drilling Southwest, L.L.C. and Sauer Drilling Company and (ii) oil and natural gas exploration, carried out by our subsidiaries Unit Petroleum Company and PetroCorp Incorporated.

The following is a summary of certain financial information on June 30, 2003 and June 30, 2004 and for the six months ended June 30, 2003 and June 30, 2004:

	June 30, 2003	June 30, 2004	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 26,839	$ 26,970	--
Long-Term Bank Debt	$ 19,000	$ 70,000	268%
Shareholders' Equity	$ 448,475	$ 553,114	23%
Ratio of Long-Term Debt to Total Capitalization	4%	11%	
Income Before Change in Accounting Principle	$ 24,350	$ 35,691	47%
Net Income	$ 25,675	$ 35,691	39%
Net Cash Provided by Operating Activities	$ 60,655	$ 94,174	55%
Net Cash Used in Investing Activities	$ (44,082)	$ (164,410)	273%
Net Cash Provided by (Used in) Financing Activities	$ (15,744)	$ 75,417	--

The following table summarizes certain operating information for the first six months of 2003 and 2004:

	2003	2004	Percent Change
Oil Production (MBbls)	238	494	108%
Natural Gas Production (MMcf)	9,810	12,908	32%
Average Oil Price Received	$ 27.86	$ 30.91	11%
Average Oil Price Received Excluding Hedge	$ 27.86	$ 32.30	16%
Average Natural Gas Price Received	$ 5.34	$ 5.24	(2%)
Average Number of Our Drilling Rigs in Use During the Period	56.8	82.6	45%
Total Number of Our Drilling Rigs Available at the End of the Period	75	89	19%

Our Bank Credit Agreement. On January 30, 2004, in conjunction with our acquisition of PetroCorp Incorporated, we replaced our credit agreement with a revolving credit facility totaling $150 million having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount. Although the current value of our assets under the latest loan value computation on May 10, 2004 supported the full $150 million, we elected, on June 1, 2004, to reduce the loan commitment from $120 million to $100 million in order to reduce financing costs since we are charged a commitment fee of .375 of 1% on the amount available but not borrowed. On July 15, 2004, we increased the loan commitment to $150 million. We incurred origination, agency and syndication fees of $515,000 at the inception of the new agreement, $40,000 of which will be paid annually and the remainder of the fees amortized over the four year life of the loan. The average interest rate for the first six months of 2004 was 2.20%. At June 30, 2004 and July 21, 2004 our borrowings were $70.0 million and at August 4, 2004, after the acquisition of Superior Pipeline Company LLC and Sauer Drilling Company and the sale of our investment in Eagle Energy Partners I LP, our borrowings were $113 million.

The loan value under our current credit facility is subject to a semi-annual re-determination on May 10 and November 10 of each year. This 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 loan value. The agreement 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 Eurodollar Rate for a 30, 60, 90 or 180 day term. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar Rate option applies may be repaid on three days prior notice to the

administrative agent subject to the payment of any applicable funding indemnification amounts. Interest on the Eurodollar Rate is computed at the Eurodollar 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 is payable at the end of each term or every 90 days whichever is less. Borrowings not under the Eurodollar 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 June 30, 2004, all of our $70.0 million debt was subject to the Eurodollar 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 credit agreement) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

Contractual Commitments. We have the following contractual obligations at June 30, 2004:

Contractual Obligations	Total	Payments Due by Period: Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Bank Debt(1)	$ 70,000	$ --	$ --	$ 70,000	$ --
Retirement Agreement(2)	1,214	300	600	314	--
Operating Leases(3)	4,153	1,056	1,960	881	256
Drill Pipe Acquisitions(4)	7,440	7,440	--	--	--
Total Contractual Obligations	$ 82,807	$ 8,796	$ 2,560	$ 71,195	$ 256

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

(2) The retirement agreement represents a contractual obligation made in the second quarter of 2001 for a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability, including accrued interest, is being paid monthly in $25,000 installments continuing through June 2009. The discounted liability is on our consolidated condensed balance sheet as part of other long-term liabilities and is presented above undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma and Houston and Midland, 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.

(4) Because of the increasing cost of steel and the potential for limited availability of new drill pipe, in the first quarter of 2004 we made a commitment to purchase approximately 275,000 feet of drill pipe by the end of 2004. At June 30, 2004 approximately 217,000 of that commitment remained outstanding.

At June 30, 2004, we 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)	$ 2,023	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,682	$ 424	Unknown	Unknown	Unknown
Plugging Liability(3)	$ 17,986	$ 225	$ 500	$ 859	$ 16,402
Gas Balancing Liability(4)	$ 1,191	Unknown	Unknown	Unknown	Unknown
Repurchase Obliga- tions(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 a liability recorded for certain properties where we believe there are insufficient 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. We made repurchases of $106,000 in 2003 for limited partners' interests. Repurchases of $14,000 were made in the first six months of 2004.

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. Each collar contract was for 10,000 MMBtu's of production per day and covered the period of April through September 2003. One contract had 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. Each contract was for 5,000 barrels of production per month and covered the period of May through December 2003. One contract had a floor price of $25.00 and a ceiling price of $32.20 and the other contact had a floor price of $26.00 and a ceiling price of $31.40. The fair value of the collar contracts was recognized on the June 30, 2003 balance sheet as a derivative liability of $119,000 and at a loss of $74,000, net of tax, in accumulated other comprehensive income. These hedges were fully effective. Natural gas revenues were reduced by $6,000 in the second quarter of 2003 due to the settlement of the June natural gas collar contract.

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 covers the period of April through October of 2004 and has a floor of $4.50 and a ceiling of $6.76. The other contract covers the period of May through October of 2004 and has a floor of $5.00 and a ceiling of $7.00. We also entered into an oil hedge covering 1,000 barrels per day of oil production.

The transaction covers the periods of February through December of 2004 and has an average price of $31.40. The fair value of the collar contracts and the oil hedge was recognized on the June 30, 2004 balance sheet as a derivative liability of $211,000 and at a loss of $131,000, net of tax, in accumulated other comprehensive income. These hedges were fully effective. The natural gas collar contracts have not changed natural gas revenues during the first six months of 2004. Oil revenues were reduced by $561,000 in the second quarter of 2004 due to the settlement of the oil hedge and oil revenues have been reduced by $687,000 for the six months ended June 30, 2004.

Self-Insurance or Retentions. We are self-insured (or have a retention) for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. The exposure (i.e. our deductible or retention) per occurrence is generally $1 million for general liability and $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. 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. With the acquisition of PetroCorp Incorporated (as previously discussed in Note 3 of the Notes to Consolidated Condensed Financial Statements), natural gas comprises 86% 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, the amount and timing of liquid natural gas imports 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 production in 2004, after the acquisition of PetroCorp Incorporated, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $205,000 per month ($2,460,000 annualized) change in our pre-tax operating cash flow. Our first six month 2004 average natural gas price was $5.24 compared to an average natural gas price of $5.34 for the first six months of 2003. A $1.00 per barrel change in our oil price would have a $83,000 per month ($996,000 annualized) change in our pre-tax operating cash flow based on our production in 2004 after the acquisition of PetroCorp Incorporated. Our first six month 2004 average oil price was $30.91 compared with an average oil price of $27.86 received in the first six months of 2003.

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.

We sell most of our natural gas production to third parties under month-to-month contracts. Several of these buyers have experienced financial complications resulting from the recent investigations into the energy trading industry. The long-term implications to the energy trading business, as well as to oil and natural gas producers because of these investigations, remains to be determined. We continue to evaluate the information available to us about our buyers and try to reduce any possible future adverse impact to us. Presently we believe that our buyers will be able to perform their commitments to us. At June

30, 2004, we owned a 16.7% limited partner interest in Eagle Energy Partners I LP, whose purchases, which are competitively marketed, accounted for 26% of our oil and natural gas revenues in the first six months of 2004. They marketed approximately 56% of the natural gas volumes we sold for ourselves and third parties during the same period. On August 2, 2004 we sold our investment in Eagle Energy Partner I LP for $6.2 million.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Any 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 73 wells (34.62 net wells) in the first six months of 2004 compared to 62 wells (24.94 net wells) in the first six months of 2003. Our total capital expenditures for oil and natural gas exploration and acquisitions in the first six months of 2004 totaled $160.7 million with $115.3 million relating to the PetroCorp Incorporated acquisition. Included in the PetroCorp Incorporated acquisition was a plugging liability and deferred tax liability of $32.1 million. Based on current prices, we plan to drill an estimated total of 165 to 175 wells in 2004 and total capital expenditures for oil and natural gas exploration and acquisitions is planned to be approximately $105 million excluding the PetroCorp Incorporated acquisition. Due to the anticipated upward trend in costs resulting from a shortage in steel, we increased our inventory of production casing and tubing from $3.1 million to $7.3 million in the first six months of 2004. This inventory will be used to meet our continued demand for such items as we complete wells in our development drilling program.

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 that 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 shortages have occurred periodically in the past. At the end of the first

quarter of 2004, we increased wages in some of our drilling areas and implemented longevity pay incentives to help maintain our contract drilling labor base. If demand for drilling rigs increases rapidly in the future, shortages of experienced personnel may limit our ability to increase the number of rigs we could operate.

We currently do not have a shortage of drill pipe. Because of increasing steel costs and the potential for future shortages of new drill pipe, we committed in the first quarter of 2004 to purchase by the end of 2004 approximately 275,000 feet of drill pipe for $9.3 million. At June 30, 2004, 217,000 feet (or approximately $7.4 million) of this commitment remains outstanding.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices heavily 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. Natural gas and oil prices began to rise since the second quarter of 2003 through the first six months of 2004 and both demand for our drilling rigs and dayrates have continued to improve. In the first six months of 2004, the average dayrate we received was $8,507 per day. The average use of our drilling rigs in the first six months of 2004 was 82.6 rigs (94%) compared with 56.8 rigs (76%) for the first six months of 2003. Based on the average utilization of our drilling rigs in the first six months of 2004, a $100 per day change in dayrates has a $8,260 per day ($3,015,000 annualized) change in our pre-tax operating cash flow. Utilization and dayrates for our drilling rigs will depend mainly on the price of natural gas.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiaries. 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 six months of 2003 and 2004, we drilled 20 and 17 wells, respectively, for our exploration and production subsidiaries. The profit received by our contract drilling segment of $702,000 and $2,017,000 during the first six months of 2003 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 December 8, 2003, we 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 million for each of the three years following the acquisition. The assets of SerDrilco Incorporated included 12 drilling rigs, spare drilling equipment, a fleet of 12 larger trucks and trailers, various other vehicles and a district office and an equipment yard in and near Borger, Texas.

On May 4, 2004, we acquired two drilling rigs and related equipment for $5.5 million. The rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. The rigs are being added into our

Rocky Mountain division and will be available to market in August and September of 2004.

On July 30 ,2004, Unit acquired Sauer Drilling Company, a Casper-based drilling company and a wholly-owned subsidiary of Tom Brown, Inc., for $34.7 million in cash and an amount equal to Sauer's working capital at closing. The amount of the working capital will be settled within 90 days of the closing. This acquisition includes 9 drilling rigs, a fleet of trucks, and an equipment and repair yard with associated inventory, located in Casper, Wyoming. Of the 9 rigs, 8 are currently operating under contract in the Wind River Basin in Wyoming and the Paradox Basin in Colorado. 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 4 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 will increase our market share within medium to shallower drilling depth ranges in our areas of operation in our Rocky Mountain Division. The equipment yard, located in Casper, Wyoming, will not only provide service space for the nine newly acquired rigs and trucks but also for our existing Rocky Mountain rig fleet.

The 2 rigs acquired on May 4 and the Sauer Drilling Company rigs are to be added into our Rocky Mountain division bringing the total rigs in that division to 19. With these two acquisitions and the completion of the construction of another rig in June 2004, our total rig fleet now consists of 100 drilling rigs.

For our contract drilling operations during the first six months of 2004, we incurred $28.9 million in capital expenditures. For the year 2004, we have budgeted capital expenditures of approximately $45 million for our contract drilling operations (excluding the $34.7 million and related costs associated with our acquisition of Sauer Drilling Company).

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. One of our wholly-owned subsidiaries is the general partner for 10 oil and natural gas limited partnerships which were formed either privately or publicly. Each partnership's revenues and costs are shared under formulas prescribed in the applicable 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 2003, the total amount paid to us for all of these fees was $873,000. We expect the fees to be approximately the same 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.

At June 30, we owned a 40% equity interest in Superior Pipeline Company LLC ("Superior"), an Oklahoma Limited Liability Company. Superior is a mid-stream company engaged primarily in the gathering, processing and treating of natural gas and owns one natural gas treatment plant, two processing plants, 12 active gathering systems and 375 miles of pipeline. Superior operates in western Oklahoma and the Texas Panhandle and has been in business for 8 years. Our investment, including our share of the equity in the earnings of that company, totaled $3.6 million at June 30, 2004 and is reported in other assets in our balance sheet. During the first six months of 2004, Superior Pipeline Company LLC purchased $2.0 million of our natural gas production and paid $19,000 for our natural gas liquids. We paid this company $15,000 for gathering and compression services in the first six months of 2004.

On July 29, 2004, we acquired the remaining 60% of Superior that we did not own for $19.8 million. This acquisition will provide us with additional alternatives to increase our ability to gather and market our (as well as third parties) natural gas and construct or acquire existing natural gas gathering and processing facilities.

On June 30, 2004, we owned a 16.7% limited partnership investment in Eagle Energy Partnership I, L.P. ("Eagle") carried at cost of $2.4 million. Eagle is engaged in the purchase and sale of natural gas, electricity (or similar electricity based products), future commodities, and the performance of scheduling and nomination services for both energy related commodities and similar energy management functions. Eagle marketed approximately 56% of the natural gas volumes we sold for ourselves and third parties in the first six months of 2004. On August 2, 2004 we sold our investment in Eagle Energy Partner I LP for $6.2 million.

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 are limited to the lower of unamortized cost or a ceiling. The ceiling is defined as the sum of the present value (10% discount rate) of estimated future net revenues from proved reserves, based on period-end oil and natural gas prices adjusted for hedging, plus the lower of cost or estimated fair value of unproved properties not 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 shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down cannot be reversed 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 on June 30, 2004 ($5.78 per Mcf for natural gas and $37.05 per barrel for oil), the unamortized cost of our 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 prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

The value and quantity of our oil and natural gas reserves is used to determine the borrowing base under our credit agreement with our banks. This amount is affected by both price changes and the measurement of oil and natural gas reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimates of oil and natural gas reserves requires extensive judgments of our reservoir engineering data and are less precise than other estimates made in connection with financial disclosures. Assigning monetary values to these estimates does not reduce the subjectivity and changing nature of oil and natural gas 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. The value and quantity of our oil and natural gas reserves are determined by our company engineers and are reviewed annually by an outside engineering firm.

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.

On January 1, 2003 the company 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. The company 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). The company does not have any assets restricted for the purpose of settling the plugging liabilities.

Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and enhancements 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 these estimates could cause us to reduce the carrying value of property and equipment.

We recognize revenues and expense generated from "daywork" drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under "footage" and "turnkey" contracts, we bear the risk of completion of the well, so revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the well is finished. 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.

NEW ACCOUNTING PRONOUNCEMENTS

On January 17, 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB 51" ("FIN 46"). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties.

FIN 46, as amended, was effective for us in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, primarily Eagle Energy Partnership I, L.P., did not have an impact on our financial position or results of operations or cash flows. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, FIN 46 and the amendment of FIN 46 were effective for us, as amended, in the quarter ending March 31, 2004. We evaluated FIN 46 and FIN 46(R) with regard to these types of entities in which we have an ownership interest and there was no material impact to the financial position, results of operations or cash flows from the adoption of FIN 46 and FIN 46(R).

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 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, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas 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 notes to our financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, we, like many other oil and gas companies, have included oil and gas extraction rights 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 extraction rights would continue to be amortized in accordance with full cost accounting rules.

The FASB has issued a proposed FASB Staff Position 142-b "Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities" (FSP 142-b) to address the application of FAS 141 to the oil and natural gas industry. If adopted as written, the proposed FSP 142-b would confirm our historical treatment of these costs. We will continue to monitor the FASB's treatment of this issue.

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 and value 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 2004 versus Second Quarter 2003

Provided below is a comparison of selected operating and financial data for the second quarter of 2004 versus the second quarter of 2003:

	Second Quarter 2003	Second Quarter 2004	Percent Change
Total Revenue	$ 72,664,000	$ 114,443,000	57%
Net Income	$ 11,691,000	$ 20,184,000	73%
Oil and Natural Gas:			
Revenue	$ 26,871,000	$ 46,334,000	72%
Operating costs	$ 5,893,000	$ 10,662,000	81%
Average natural gas price (Mcf)	$ 4.74	$ 5.57	18%
Average oil price (Bbl)	$ 25.51	$ 31.12	22%
Natural gas production (Mcf)	4,955,000	6,614,000	33%
Oil production (Bbl)	123,000	278,000	126%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.12	$ 1.38	23%
Depreciation, depletion and amortization	$ 6,445,000	$ 11,535,000	79%
Drilling:			
Revenue	$ 45,221,000	$ 67,110,000	48%
Operating costs	$ 33,641,000	$ 48,364,000	44%
Percentage of revenue from daywork contracts	97%	100%	
Average number of rigs in use	62.4	83.7	34%
Average dayrate on daywork contracts	$ 7,601	$ 8,751	15%
Depreciation	$ 5,899,000	$ 7,754,000	31%
General and Administrative Expense	$ 2,070,000	$ 3,103,000	50%
Interest Expense	$ 175,000	$ 514,000	194%
Average Interest Rate	2.17%	2.21%	2%
Average Long-Term Debt Outstanding	$ 22,968,000	$ 75,211,000	227%

Oil and natural gas revenues increased due to increases in both oil and natural gas produced and from increases in oil and natural prices between the second quarter of 2004 and the second quarter of 2003. PetroCorp Incorporated was acquired on January 30, 2004 and its production is included in our operating results subsequent to the acquisition date. Oil production was up 126% between the comparative quarters. Approximately 54% of the increase was from the

production added through the PetroCorp Incorporated acquisition. Natural gas production was up 33% between the comparative quarters. Approximately 58% of the increase in natural gas production was from wells acquired through the PetroCorp

Incorporated acquisition. The remainder of the increase in production for both oil and natural gas came from wells added through our development drilling program. Total operating cost increased in the second quarter of 2004 when compared with the second quarter of 2003 due mainly from the acquisition of PetroCorp Incorporated and to a lesser extent from costs associated with the addition of new wells from our drilling program. PetroCorp Incorporated has historically experienced higher operating cost per equivalent barrel due to the types of wells under production and the reserve base being more oil. Gross production taxes which are based on a percentage of revenues were also higher. 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. The acquisition of PetroCorp Incorporated was made at a higher cost per equivalent volumes than we have previously experienced through both our drilling program and from other acquisitions on average. During 2003 and the first six months of 2004, we also experienced higher cost per Mcfe for the discovery of new reserves through our development drilling program.

Contract drilling revenues increased between the comparative quarters due to increases in demand for our drilling rigs and increases in dayrates. Natural gas prices remained between $4.00 and $5.50 through most of 2003 and continued at that level into the first six months of 2004 causing an increase in demand for our rigs. Dayrates, which typically increase after the increase in demand for rigs, also started increasing in the second quarter of 2003 and have continued to steadily increase throughout the first six months of 2004. Along with the increase in demand we also added 12 drilling rigs with the acquisition of SerDrilco, Inc. in December of 2003 contributing to the increase in total drilling revenues and operating cost. We did not drill any turnkey or footage wells in the second quarter of 2004. Approximately 3% 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 12 rigs in the fourth quarter of 2003 and increased rig utilization.

General and administrative expense was higher in the second quarter of 2004 due to increases in employee, insurance and audit related costs. Our total interest expense was higher due to the additional debt incurred from the PetroCorp Incorporated acquisition. Income tax expense increased primarily due to the increase in income before income taxes. Current income tax expense increased in the second quarter of 2004 due to an increase in the provision for alternative minimum tax which was based on higher estimates of total taxable income for the year.

First Six Months 2004 versus First Six Months 2003

Provided below is a comparison of selected operating and financial data for the first six months of 2004 versus the first six months of 2003:

	First Six Months 2003	First Six Months 2004	Percent Change
Total Revenue	$ 141,223,000	$ 216,343,000	53%
Income Before Change in Accounting Principle	$ 24,350,000	$ 35,691,000	47%
Net Income	$ 25,675,000	$ 35,691,000	39%
Oil and Natural Gas:			
Revenue	$ 60,119,000	$ 84,324,000	40%
Operating costs	$ 12,508,000	$ 20,394,000	63%
Average natural gas price (Mcf)	$ 5.34	$ 5.24	(2%)
Average oil price (Bbl)	$ 27.86	$ 30.91	11%
Natural gas production (Mcf)	9,810,000	12,908,000	32%
Oil production (Bbl)	238,000	494,000	108%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.10	$ 1.36	24%
Depreciation, depletion and amortization	$ 12,492,000	$ 21,712,000	74%
Drilling:			
Revenue	$ 79,787,000	$ 130,324,000	63%
Operating costs	$ 61,452,000	$ 94,920,000	54%
Percentage of revenue from daywork contracts	96%	100%	
Average number of rigs in use	56.8	82.6	45%
Average dayrate on daywork contracts	$ 7,476	$ 8,507	14%
Depreciation	$ 10,793,000	$ 15,218,000	41%

General and Administrative Expense	$	4,520,000	$	5,874,000	30%
Interest Expense	$	386,000	$	931,000	141%
Average Interest Rate		2.13%		2.20%	3%
Average Long-Term Debt Outstanding	$	27,266,000	$	65,615,000	141%

Oil and natural gas revenues increased due to increases in both oil and natural gas produced and to a lesser extent from an increase in oil prices between the first six months of 2004 and the first six months of 2003. A reduction in natural gas prices partially offset the increases. PetroCorp Incorporated was acquired on January 30, 2004 and its production is included in our operating results subsequent to the acquisition date. Oil production was up

108% with approximately 61% of the increase from the production added through the PetroCorp Incorporated acquisition. Natural gas production was up 32% with approximately 53% of the increase in natural gas production from wells acquired through the PetroCorp Incorporated acquisition. The remainder of the increase in production for both oil and natural gas came from wells added through our development drilling program. Total operating cost increased in the first six months of 2004 when compared with the first six months of 2003 due mainly from the acquisition of PetroCorp Incorporated and to a lesser extent from costs associated with the addition of new wells from our drilling program. PetroCorp Incorporated has historically experienced higher operating cost per equivalent barrel due to the types of wells under production and the reserve base being more toward oil. Gross production taxes which are based on a percentage of revenues were also higher. 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. The acquisition of PetroCorp Incorporated was made at a higher cost per equivalent volumes than we have previously experienced through both our drilling program and from other acquisitions on average. During 2003 and the first six months of 2004, we also experienced higher cost per Mcfe for the discovery of new reserves through our development drilling.

Contract drilling revenues increased due to increases in demand for our drilling rigs and increases in dayrates. Natural gas prices remained between $4.00 and $5.50 through most of 2003 and continued at that level into the first six months of 2004 causing an increase in demand for our rigs. Dayrates, which typically increase after the increase in demand for rigs, also started increasing in the second quarter of 2003 and have continued to steadily increase throughout the first six months of 2004. Along with the increase in demand we also added 12 drilling rigs with the acquisition of SerDrilco, Inc. in December of 2003 contributing to the increase in total drilling revenues and operating cost. We did not drill any turnkey or footage wells in the first six months of 2004. Approximately 4% 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. Contract drilling depreciation increased due to the utilization associated with the 12 rigs acquired in the fourth quarter of 2003 and increases in utilization from the remainder of our rigs.

General and administrative expense was higher in the six months of 2004 due to increases in employee, insurance and auditing costs. Our total interest expense was higher due to the additional debt incurred from the PetroCorp Incorporated acquisition. Income tax expense increased primarily due to the increase in income before income taxes. Current income tax expense increased in the first six months of 2004 due to an increase in the provision for alternative minimum tax which was based on higher estimates of total taxable income for the year.

Net income in the first six months of 2003 includes $1.3 million of income due to a change in accounting principle for the implementation of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143).

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. We do not use derivative financial instruments for speculative or trading purposed.

Commodity Price Risk

We produce, purchase and sell crude oil, natural gas, condensate and natural gas liquids. As a result, our financial results can be significantly impacted as these commodity prices fluctuate widely in response to changing market forces. Relatively modest changes in gas prices significantly impact our results of operations and cash flows.

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 prices 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.

Interest Rate Risk

Our interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based, on borrowings from our banks. At June 30, 2004, all of our bank debt was at LIBOR-based rates. In the past, we have not entered into financial instruments such as interest rate swaps or interest rate lock agreements.

Item 4. Controls and Procedures

We maintain a set of disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed in our reports filed under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms. We have investments in certain unconsolidated entities that we do not control or manage. As we do not control or manage these entities, our disclosure controls and procedures with respect to such entities are necessarily more limited than those we maintain with respect to our consolidated subsidiaries.

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 timely alerting them to material information required to be included in our periodic SEC filings relating to the company (including its consolidated subsidiaries).

There has been no change in our internal control over financial reporting during the quarter ended June 30, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

Not applicable

Item 3. Defaults Upon Senior Securities

Not applicable

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

On May 5, 2004 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 William B. Morgan, John H. Williams and Larry D. Pinkston to serve as directors.

Nominee	Numbers of Votes For	Against or Withheld
William B. Morgan	41,042,218	591,593
John H. Williams	41,067,199	566,612
Larry D. Pinkston	40,646,900	986,911

The following directors, whose term of office did not expire at the annual meeting, continue as directors of the Company: King P. Kirchner, Don Cook, J. Michael Adcock, John G. Nikkel, John S. Zink and Mark E. Monroe.

II. Ratification of the appointment of PricewaterhouseCoopers L L P as the Company's independent certified public accountants for the fiscal year 2004.

For	-	41,222,799
Against	-	397,721
Abstain	-	13,291

Item 5. Other Information

Not applicable

Item 6. Exhibits and Reports on Form 8-K

(a) 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.

(b) On April 19, 2004, we filed a report on Form 8-K under item 7, 9 and

12. This report announced our earnings for the quarter ended March 31, 2004 in an attached exhibit.

On April 20, 2004, we filed a report on Form 8-K under item 7 and 9. This report announced that we have reached an agreement to buy two drilling rigs and related equipment for $5.5 million.

On June 29, 2004, we filed a report on Form 8-K under item 7 and 9. This report announced that we had signed an agreement to acquire Sauer Drilling Company, a Casper-based drilling company and a wholly-owned subsidiary of Tom Brown, Inc., for $34.7 million in cash and an amount equal to Sauer's working capital at closing.

On July 21, 2004, we filed a report on Form 8-K under item 7, 9 and 12. This report announced our earnings for the quarter ended June 30, 2004 in an attached exhibit and also announced that we had reached an agreement to acquire the 60% of Superior Pipeline Company LLC that we did not previously own for $19.8 million.

On August 4, 2004, we filed a report on Form 8-K under item 7 and 9. This report announced that our wholly-owned subsidiary, Unit Drilling Company, had completed the acquisition of Sauer Drilling Company, a Casper-based drilling company and a wholly-owned subsidiary of Tom Brown, Inc. The report also announced that we had completed the acquisition of the 60% of Superior Pipeline Company LLC that we did not already own.

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 6, 2004	By: /s/ John G. Nikkel
		JOHN G. NIKKEL Chief Executive Officer, and Director
Date:	August 6, 2004	By: /s/ David T. Merrill
		DAVID T. MERRILL Chief Financial Officer and Treasurer

Exhibit 15

August 6, 2004

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

Commissioners:

We are aware that our report dated August 4, 2004 on our review of interim financial information of Unit Corporation for the three and six month periods ended June 30, 2003 and 2004 and included in the Company's quarterly report on Form 10-Q for the quarter ended June 30, 2004 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, 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 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: August 6, 2004

/s/ John G. Nikkel

JOHN G. NIKKEL
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: August 6, 2004

/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 June 30, 2004 (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, 2004 and December 31, 2003 and for three and six month periods ended June 30, 2004 and 2003.

Dated: August 6, 2004

By: /s/ John G. Nikkel
- ------------------------
John G. Nikkel
Chief Executive Officer

Dated: August 6, 2004

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.