SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

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

For the quarterly period ended June 30, 2002
OR

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

For the transition period from _________ to _________
[Commission File Number 1-9260]

U N I T C O R P O R A T I O N

(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1000 Kensington Tower I, 7130 South Lewis, Tulsa, Oklahoma	**74136**
(Address of principal executive offices)	**(Zip Code)**

(918) 493-7700
(Registrant's telephone number, including area code)

None
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes _X_ No ___

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

Common Stock, $.20 par value	**36,114,700**
Class	**Outstanding at August 9, 2002**

FORM 10-Q
UNIT CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEETS (UNAUDITED)

	December 31, 2001	June 30, 2002
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 391	$ 1,458
Accounts receivable	33,886	27,817
Materials and supplies	5,358	6,908
Income tax receivable	3,198	-
Other	3,761	3,745
Total current assets	46,594	39,928
Property and Equipment:		
Total cost	666,861	691,425
Less accumulated depreciation, depletion, amortization and impairment	304,643	321,123
Net property and equipment	362,218	370,302
Other Assets	8,441	8,261
Total Assets	$ 417,253	$ 418,491
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities:		
Current portion of long-term liabilities and debt	$ 1,893	$ 1,375
Accounts payable	16,292	16,265
Accrued liabilities	10,856	9,927
Total current liabilities	29,041	27,567
Long-Term Debt	31,000	20,000
Other Long-Term Liabilities	4,110	4,364
Deferred Income Taxes	73,940	78,381
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, 36,006,267 and 36,114,300 shares issued, respectively	7,201	7,223
Capital in excess of par value	141,977	142,926
Accumulated other comprehensive income	-	-
Retained earnings	130,280	138,030
Treasury Stock, at cost, 30,000 shares	(296)	-
Total shareholders' equity	279,162	288,179
Total Liabilities and Shareholders' Equity	$ 417,253	$ 418,491

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2002	2001	2002
	(In thousands except per share amounts)			
Revenues:				
Contract drilling	$ 44,836	$ 25,841	$ 80,336	$ 52,555
Oil and natural gas	25,522	18,668	60,242	30,629
Other	729	244	952	299
Total revenues	71,087	44,753	141,530	83,483
Expenses:				
Contract drilling:				
Operating costs	23,997	20,137	46,427	39,269
Depreciation and amortization	3,602	2,928	6,821	5,739
Oil and natural gas:				
Operating costs	5,526	5,161	12,005	10,109
Depreciation, depletion and amortization	5,142	5,988	9,820	11,257
General and administrative	3,031	2,013	4,834	4,042
Interest	719	229	1,691	516
Total expenses	42,017	36,456	81,598	70,932
Income Before Income Taxes	29,070	8,297	59,932	12,551
Income Tax Expense:				
Current	3,342	238	7,739	360
Deferred	7,680	2,951	14,973	4,441
Total income taxes	11,022	3,189	22,712	4,801
Net Income	$ 18,048	$ 5,108	$ 37,220	$ 7,750
Net Income Per Common Share:				
Basic	$ .50	$ 0.14	$ 1.04	$ 0.21
Diluted	$ .50	$ 0.14	$ 1.03	$ 0.21

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

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

	Six Months Ended June 30,	
	2001	2002
	(In thousands)	
Cash Flows From Operating Activities:		
Net income	$ 37,220	$ 7,750
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, depletion, and amortization	16,970	17,313
Deferred tax expense	14,973	4,441
Other	1,851	198
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(11,621)	6,069
Accounts payable	7,268	4,050
Other – net	(3,532)	990
Net cash provided by operating activities	63,129	40,811
Cash Flows From (Used In) Investing Activities:		
Capital expenditures	(57,873)	(29,188)
Proceeds from disposition of assets	1,147	907
Other-net	(812)	459
Net cash used in investing activities	(57,538)	(27,822)
Cash Flows From (Used In) Financing Activities:		
Net borrowings (payments) under line of credit	(4,500)	(11,000)
Net payments of notes payable and other long-term debt	-	(22)
Proceeds from stock sales	540	204
Book overdrafts	(1,590)	(1,104)
Net cash used in financing activities	(5,550)	(11,922)
Net Increase in Cash and Cash Equivalents	41	1,067
Cash and Cash Equivalents, Beginning of Year	726	391
Cash and Cash Equivalents, End of Period	$ 767	$ 1,458

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,	
	2001	2002	2001	2002
	(In thousands)			
Net Income	$ 18,048	$ 5,108	$ 37,220	$ 7,750
Other Comprehensive Income, Net of Taxes:				
Change in value of cash flow derivative instruments used as cash flow hedges	551	-	551	-
Comprehensive Income	$ 18,599	$ 5,108	$ 37,771	$ 7,750

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 (the "Company") and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. As applicable under these regulations, certain information and footnote disclosures have been condensed or omitted and the consolidated condensed financial statements do not include all disclosures required by generally accepted accounting principles. In the opinion of the Company, the unaudited consolidated condensed financial statements contain all adjustments necessary (all adjustments are of a normal recurring nature) to present fairly the interim financial information.

Results for the three and six months ended June 30, 2002 are not necessarily indicative of the results to be realized during the full year. The condensed financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2001. Our independent accountants have performed a review of these interim financial statements in accordance with standards established by the American Institute of Certified Public Accountants. Pursuant to Rule 436(c) under the Securities Act of 1933, their report of that review should not be considered as part of any registration statements prepared or certified by them within the meaning of Section 7 and 11 of that Act and the independent accountants' liability under Section 11 does not extend to it.

NOTE 2 - EARNINGS PER SHARE

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

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
For the Three Months Ended June 30, 2001:			
Basic earnings per common share	$ 18,048,000	35,972,000	$ 0.50
Effect of dilutive stock options	-	370,000	
Diluted earnings per common share	$ 18,048,000	36,342,000	$ 0.50
For the Three Months Ended June 30, 2002:			
Basic earnings per common share	$ 5,108,000	36,109,000	$ 0.14
Effect of dilutive stock options	-	296,000	
Diluted earnings per common share	$ 5,108,000	36,405,000	$ 0.14

All options and their average exercise prices for the three months ended June 30, 2001 were included in the computation of diluted earnings per share. The following options and their average exercise prices were not included in the computation of diluted earnings per share for the three months ended June 30, 2002 because the option exercise prices were greater than the average market price of common shares:

	2002
Options	21,000
Average exercise price	$ 20.10

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	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
For the Six Months Ended June 30, 2001:			
Basic earnings per common share	$ 37,220,000	35,942,000	$ 1.04
Effect of dilutive stock options	-	368,000	
Diluted earnings per common share	$ 37,220,000	36,310,000	$ 1.03
For the Six Months Ended June 30, 2002:			
Basic earnings per common share	$ 7,750,000	36,072,000	$ 0.21
Effect of dilutive stock options	-	264,000	
Diluted earnings per common share	$ 7,750,000	36,336,000	$ 0.21

All options and their average exercise prices for the six months ended June 30, 2001 were included in the computation of diluted earnings per share. The following options and their average exercise prices were not included in the computation of diluted earnings per share for the six months ended June 30, 2002 because the option exercise prices were greater than the average market price of common shares:

	2002
Options	174,000
Average exercise price	$ 17.19

NOTE 3 - NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2002, we adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142). For goodwill and intangible assets already recorded in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has changed. The unamortized balance of goodwill, all of which relates to our drilling segment, was $5,088,000 at January 1, 2002 and June 30, 2002. We previously expensed $243,000 annually for the amortization of goodwill. The impact from the adoption of FAS 142 on our financial position or results of operations was not material to the current and prior periods.

On January 1, 2002, we adopted Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144). This statement supersedes Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. The impact from the adoption of FAS 144 on our financial position or results of operations was not material.

In July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002 (January 1, 2003 for us) and 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). We are currently evaluating our oil and natural gas properties to determine the impact of the adoption of FAS 143 on our financial position and results of operations.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13, and Technical Corrections" (FAS 145). FAS 145 is effective for fiscal years beginning after May 15, 2002. In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Cost Associated with Exit or Disposal Activities" (FAS 146). FAS 146 is effective for exit and disposal activities initiated after December 31, 2002. We have not yet determined the effect of the adoption of FAS 145 and FAS 146 on our financial position, results of operations or cashflows.

NOTE 4 - INDUSTRY SEGMENT INFORMATION

The company has two business segments: Contract Drilling, and Oil and Natural Gas, representing its two strategic business units offering different products and services. The Contract Drilling segment provides land contract drilling of oil and natural gas wells and the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties. The company evaluates the performance of its operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. The company has natural gas production in Canada, which is not significant. Information regarding the company's operations by industry segment for the three and six month periods ended June 30, 2001 and 2002 is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	**2002**	**2001**	**2002**
	(In thousands)			
Revenues:				
Contract drilling	$ 44,836	$ 25,841	$ 80,336	$ 52,555
Oil and natural gas	25,522	18,668	60,242	30,629
Other	729	244	952	299
	$ 71,087	$ 44,753	$ 141,530	$ 83,483
Operating Income (1):				
Contract drilling	$ 17,237	$ 2,776	$ 27,088	$ 7,547
Oil and natural gas	14,854	7,519	38,417	9,263
	32,091	10,295	65,505	16,810
General and administrative expense	(3,031)	(2,013)	(4,834)	(4,042)
Interest expense	(719)	(229)	(1,691)	(516)
Other income - net	729	244	952	299

$ 29,070	8,297	$ 59,932	$ 12,551
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(1) Operating income is total operating revenues less operating expenses, depreciation, depletion and amortization and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

REPORT OF REVIEW BY INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying consolidated condensed balance sheet of Unit Corporation and subsidiaries as of June 30, 2002, and the related consolidated condensed statements of operations and comprehensive income for the three and six month periods ended June 30, 2002 and 2001 and cash flows for the six month period ended June 30, 2002 and 2001. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical review procedures to financial data and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

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

We have previously audited, in accordance with generally accepted auditing, the consolidated balance sheet as of December 31, 2001, and the related consolidated statements of operations, stockholder’s equity and cash flows for the year then ended (not presented herein); and in our report, dated February 20, 2002, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2001, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers L L P

Tulsa, Oklahoma
July 23, 2002

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

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FINANCIAL CONDITION

Summary. Our financial condition and liquidity depends on the cash flow from our two principal subsidiaries and borrowings under our bank loan agreement. At June 30, 2002, we had cash totaling $1,458,000 and we had borrowed $20.0 million of the $40.0 million we have elected to have available under our loan agreement.

The following summarizes certain financial information on June 30, 2002 and for the six months ended June 30, 2002:

Working capital	$ 12,361,000
Net income	$ 7,750,000
Net cash provided by operating activities	$ 40,811,000
Long-term debt	$ 20,000,000
Shareholders' equity	$ 288,179,000
Ratio of long-term debt to total capitalization	6%

The following table summarizes certain operating information for the first six months of 2001 and 2002:

	2001	2002	Percent Change
Oil production (Bbls)	253,000	227,000	(10%)
Natural gas production (Mcf)	9,509,000	9,653,000	2%
Average oil price received	$ 26.39	$ 19.83	(25%)
Average natural gas price received	$ 5.45	$ 2.53	(54%)
Average number of our drilling rigs in use during the period	48.0	33.0	(31%)

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

Each year, on April 1 and October 1, our banks redetermine the loan value of our assets. This value is mainly based on an amount equal to a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of our drilling rig fleet, limited to $20 million, is added to the loan value. Our loan agreement provides for a revolving credit facility, which ends on May 1, 2005 followed by a three-year term loan. Borrowing under our loan agreement totaled $30.0 million at December 31, 2001 and $18.3 million on July 23, 2002.

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

The interest rate on our bank debt was 2.88 percent and 2.89 percent at June 30, 2002 and July 23, 2002, respectively. At our election, any portion of our outstanding bank debt may be fixed at the Libor Rate, as adjusted depending on the level of our debt as a percentage of the amount available for us to borrow. The Libor Rate may be fixed for periods of up to 30, 60, 90 or 180 days with the balance of our bank debt being subject to the Prime Rate. During any Libor Rate funding period, we may not pay any part of the outstanding principal balance which is subject to the Libor Rate. Borrowings subject to the Libor Rate were $20.0 million and $18.0 million at June 30, 2002 and July 23, 2002, respectively.

The loan agreement also requires us to maintain:

- consolidated net worth of at least $125 million;
- a current ratio of not less than 1 to 1;
- a ratio of long-term debt, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.2 to 1;
- a ratio of total liabilities, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.65 to 1; and
- working capital provided by operations, as defined in the loan agreement, cannot be less than $40 million in any year.

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

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. We entered into a collar contract covering approximately 25 percent of our daily oil production from November 1, 2000 through February 28, 2001. The collar had a floor of $26.00 per barrel and a ceiling of $33.00 per barrel and we received $0.86 per barrel for entering into the transaction. During the first quarter of 2001, our oil hedging transaction yielded an increase in our oil revenues of $17,200.

During the second quarter of 2001, we entered into a natural gas collar contract for approximately 36 percent of our June and July 2001 production, at a floor price of $4.50 and a ceiling price of $5.95. During the second quarter of 2001, the June collar contract increased natural gas revenues by $516,000. The July collar was recognized on our June 30, 2001 balance sheet at $551,000, net of tax, in accumulated other comprehensive income. On April 30, 2002, we entered into a collar contract covering approximately 19 percent of our natural gas production for the periods of April 1, 2002 thru October 31, 2002. The collar has a floor of $3.00 and a ceiling of $3.98. During the second quarter of 2002, our natural gas hedging transactions had no effect on our natural gas revenues and the value of the remaining months contracts was not material at June 30, 2002.

Self-Insurance. Unit is self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. Given the recent tightening in the insurance market our self-insurance levels have significantly increased. Effective August 1, 2002, our exposure (i.e. our deductible or retention) per occurrence range from $200,000 for general liability to $1 million for rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain claims. There is no assurance that such coverage will adequately protect Unit against liability from all potential consequences.

Our Oil and Natural Gas Operations. Natural gas comprises about 89 percent of our total oil and natural gas reserves. Any noticeable change in natural gas prices has a significant affect on our revenues, cash flow and the value of our oil and natural gas reserves.

Based on our 2002 first six month production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $150,000 per month ($1,800,000 annualized) change in our pre-tax cash flow. Our first six month 2002 average natural gas price was $2.53 compared to an average natural gas price of $5.45 received in the first six months of 2001. A $1.00 per barrel change in our oil price would have a $35,000 per month ($420,000 annualized) change in our pre-tax cash flow. Our first six months 2002 average oil price was $19.83 compared with an average oil price of $26.39 received in the first six months of 2001.

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 of the carrying value of our oil and natural gas properties. Also, price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our bank loan agreement since that determination is based mainly on the value of our oil and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

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. Presently we believe that our buyers will be able to perform their commitments to us. However, we will continue to check the information available to us about these buyers in an effort to reduce any possible future adverse impact to us.

Our decisions on whether we try 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 to incur such costs. We drilled 33 wells in the first six months of 2002 compared to 64 wells in the first six months 2001. Based on current prices, we plan to drill an estimated 125 wells and expect to make total capital expenditures of about $55 million for exploration, development drilling and acquisition of oil and natural gas properties in 2002.

Contract Drilling. Our drilling work is subject to many factors that influence the number of rigs we have working as well as the costs and revenues associated with such work. These factors include competition from other drilling contractors, the prevailing prices for natural gas and oil, labor to run our rigs and our ability to supply the equipment needed. We have not encountered major difficulty in hiring and keeping rig crews, but such shortages have occurred periodically in the past. If demand for drilling rigs was to increase rapidly in the future, shortages of experienced personnel would limit our ability to increase the number of rigs we could operate.

Low oil and natural gas prices during most of the 1980’s and 1990’s reduced demand for domestic land contract drilling rigs. However, in the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a big increase in demand for our rigs. Demand continued to increase until the end of the third quarter of 2001 and reached a high when

52 of our rigs were working in July 2001. Because of declining natural gas prices throughout 2001, demand for our rigs dropped significantly in the fourth quarter of 2001. Average use of our rigs in the first six months of 2002 was 33.0 rigs compared with 48.0 rigs for the first six months of 2001.

As demand for our rigs increased during 2001 so did the dayrates we received. Our average dayrate reached $11,142 by September of 2001. However, as demand began to decrease, so did our rates. Our average dayrate in the first six months of 2002 was $8,055 compared to $9,486 for the first six months of 2001. Based on the average utilization of our rigs in the first six months of 2002, a $100 per day change in dayrates has a $3,300 per day ($1,205,000 annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated parties. The profit received by our contract drilling segment of $1,101,000 and $542,000 in the first six months of 2001 and 2002, 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.

Acquisitions. On June 24, 2002 we signed definitive agreements to acquire twenty drilling rigs and related equipment for 7.22 million shares of our common stock and $4.5 million in cash. These agreements also give us the exclusive first option to purchase any additional rigs constructed by one of the sellers within the next three years. These acquisitions should be completed by the middle of the third quarter. All of the rigs are operational and range in horsepower from 650 to 2,000 with 15 having a horsepower rating of 1,000 or more. Depth capacities range from 12,000 to 25,000 feet and twelve of the rigs are SCR electric. The addition of these twenty rigs will bring our fleet to 75, 74 of which will be capable of operating. For 2002, we anticipate spending approximately $20 million on our drilling operations excluding the twenty-rig acquisition detailed above.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for eighteen oil and natural gas partnerships which were formed privately and publicly. The partnership’s revenues and costs are shared under formulas prescribed in each limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party’s share of such costs. These costs are billed on the same basis as billings to unrelated 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 2001, the total paid to us for all of these fees was $1,107,000 and we expect the fees to be about the same in 2002. 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, 2002, we owned a 40 percent equity interest in a natural gas gathering and processing company. Our balance sheet investment and equity in the company totaled $1.3 million at June 30, 2002. From time to time we may guarantee the debt of this company. However, as of June 30, 2002 and July 23, 2002, we were not guaranteeing any of the debt of this company.

One of our subsidiaries owns 4,949,500 shares of common stock and 1,800,000 warrants of Shenandoah Resources Ltd. (“Shenandoah”), a Canadian oil and natural gas exploration and production company. In the second quarter of 2002 Shenandoah obtained an order under Canadian Law protecting it from its creditors while it worked out a financial restructuring plan. On July 17, 2002, Longbow Energy Corporation (“LongBow”) and Shenandoah jointly announced that they have executed a Letter of Intent whereby LongBow will acquire all of the issued and outstanding shares of Shenandoah and settle the outstanding claims of Shenandoah’s secured and unsecured creditors. The business of LongBow and Shenandoah is to be combined upon the implementation of a Plan of Arrangement conducted in accordance with the provisions of the Companies’ Creditors Arrangement Act (Canada) and, if required, the Business Corporations Act (Alberta). Our investment of $346,000 in Shenandoah is part of other assets in our consolidated balance sheet.

Outlook. We expect that for the balance of 2002 the number of our rigs working will remain at second quarter levels and that dayrates should stay just above $7,500 per day depending mainly on the price of natural gas for the remainder of 2002 and beyond.

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

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have large downward revisions in our estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil and natural gas prices in effect on June 30, 2002 ($3.01 per Mcf for natural gas and $24.40 per barrel for oil), the unamortized cost of our domestic oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas prices remain erratic and any significant declines below quarter-end prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

The value of our oil and natural gas reserves is used to decide the loan value under our loan agreement. This value is affected by both price changes and the measurement of reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimate of oil and natural gas reserves require extensive judgments of our reservoir engineering data and are less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such 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.

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

Under “footage” and “turnkey” contracts, we bear the risk of completion of the well, so revenues and expenses are recognized using the completed contract method. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined. 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.

SAFE HARBOR STATEMENT

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

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

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

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

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

RESULTS OF OPERATIONS

Second Quarter 2002 versus Second Quarter 2001

Provided below is a comparison of selected operating and financial data for the second quarter of 2002 verses the second quarter of 2001:

	Second Quarter 2001	Second Quarter 2002	Percent Change
Total Revenue	$ 71,087,000	$ 44,753,000	(37%)
Net Income	$ 18,048,000	$ 5,108,000	(72%)
Oil and Natural Gas:			
Revenue	$ 25,522,000	$ 18,668,000	(27%)
Average natural gas price (Mcf)	$ 4.37	$ 3.00	(31%)
Average oil price (Bbl)	$ 25.69	$ 22.59	(12%)
Natural gas production (Mcf)	4,871,000	5,097,000	5%
Oil production (Bbl)	129,000	110,000	(15%)
Operating profit (revenue less operating costs)	$ 19,996,000	$ 13,507,000	(32%)
Operating margin	78%	72%	
Depreciation, depletion and amortization rate (Mcfe)	$ 0.90	$ 1.03	14%
Depreciation, depletion and amortization	$ 5,142,000	$ 5,988,000	16%
Drilling:			
Revenue	$ 44,836,000	$ 25,841,000	(42%)
Percentage of revenue from daywork contracts	100%	85%	(15%)
Average number of rigs in use	50.0	33.2	(34%)
Average dayrate on daywork contracts	$ 10,202	$ 7,698	(25%)
Operating profit (revenue less operating costs)	$ 20,839,000	$ 5,704,000	(73%)
Operating margin	46%	22%	
Depreciation	$ 3,602,000	$ 2,928,000	(19%)
General and Administrative Expense	$ 3,031,000	$ 2,013,000	(34%)
Interest Expense	$ 719,000	$ 229,000	(68%)
Average Interest Rate	5.9%	3.0%	(49%)

Average Long-Term Debt Outstanding	$ 45,644,000	$ 23,470,000	(49%)

Significantly lower oil and natural gas prices, which led to lower demand for our drilling rigs and decreases in contract drilling dayrates all contributed to decreases in our revenues and net income in the second quarter of 2002 as compared to the second quarter of 2001.

Oil and natural gas revenues, operating profits and operating profit margins were all negatively affected by lower prices received for both oil and natural gas between the second quarter of 2002 and the second quarter of 2001. Increased natural gas production partially offset the decrease in natural gas prices. Total operating cost decreased due to lower gross production taxes, since the tax is based on a percentage of oil and natural gas revenues. Depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties increased due to higher equivalent production between the comparative quarters and an increase in our DD&A rate per Mcfe. We are experiencing higher cost per Mcfe for the discovery of new reserves resulting in an increase in the DD&A rate.

Reduced natural gas prices caused decreases in operator demand for contract drilling rigs within our working area and resulted in lower rig use and dayrates for our rigs. As a result, operating margins and total operating cost both declined between the second quarter of 2002 and the second quarter of 2001. Approximately 15 percent of our total drilling revenues in the second quarter of 2002 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. We did not drill any footage or turnkey wells in the second quarter of 2001. Contract drilling depreciation decreased due to lower rig use.

General and administrative expense was higher in the second quarter of 2001 because we recorded $1.3 million in additional employee benefit expenses for the present value of the separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense will be paid in monthly payments starting in July 2003 and continuing through June 2009. Our total interest expense is lower due to lower interest rates along with a substantial reduction in our long-term debt.

Six Months 2002 versus Six Months 2001

Provided below is a comparison of selected operating and financial data for the first six months of 2002 verses the first six months of 2001:

	First Six Months of 2001	First Six Months of 2002	Percent Change
Total Revenue	$ 141,530,000	$ 83,483,000	(41%)
Net Income	$ 37,220,000	$ 7,750,000	(79%)
Oil and Natural Gas:			
Revenue	$ 60,242,000	$ 30,629,000	(49%)
Average natural gas price (Mcf)	$ 5.45	$ 2.53	(54%)
Average oil price (Bbl)	$ 26.39	$ 19.83	(25%)
Natural gas production (Mcf)	9,509,000	9,653,000	2%
Oil production (Bbl)	253,000	227,000	(10%)
Operating profit (revenue less operating costs)	$ 48,237,000	$ 20,520,000	(57%)
Operating margin	80%	67%	
Depreciation, depletion and amortization rate (Mcfe)	$ 0.88	$ 1.01	15%
Depreciation, depletion and amortization	$ 9,820,000	$ 11,257,000	15%
Drilling:			
Revenue	$ 80,336,000	$ 52,555,000	(35%)
Percentage of revenue from daywork contracts	100%	91%	(9%)
Average number of rigs in use	48.0	33.0	(31%)
Average dayrate on daywork contracts	$ 9,486	$ 8,055	(15%)
Operating profit (revenue less operating costs)	$ 33,909,000	$ 13,286,000	(61%)
Operating margin	42%	25%	
Depreciation	$ 6,821,000	$ 5,739,000	(16%)
General and Administrative Expense	$ 4,834,000	$ 4,042,000	(16%)
Interest Expense	$ 1,691,000	$ 516,000	(69%)
Average Interest Rate	6.6%	3.0%	(55%)
Average Long-Term Debt Outstanding	$ 49,311,000	$ 26,075,000	(47%)

Significantly lower oil and natural gas prices, which led to lower demand for our drilling rigs and decreases in contract drilling dayrates all contributed to decreases in our revenues and net income in the first six months of 2002 as compared to the first six months of 2001.

Oil and natural gas revenues, operating profits and operating profit margins were all negatively affected by lower prices received for both oil and natural gas between the first six months of 2002 and the first six months of 2001. On an Mcfe basis, production declines in oil were offset by increased natural gas production between the comparative periods. Total operating cost decreased due to lower gross production taxes, since the tax is based on a percentage of oil and natural gas revenues. Depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties increased due to an increase in our DD&A rate per Mcfe. We are experiencing higher cost per Mcfe for the discovery of new reserves resulting in an increase in the DD&A rate.

Reduced natural gas prices caused decreases in operator demand for contract drilling rigs within our working area and resulted in lower rig use and dayrates for our rigs. As a result, operating margins and total operating cost both declined between the first six months of 2002 and the first six months of 2001. Approximately 9 percent of our total drilling revenues in the first six months of 2002 came from footage and turnkey contracts, which had profit margins less than our daywork contracts. We did not drill any footage or turnkey wells in the first half of 2001. Contract drilling depreciation decreased due to lower rig use.

General and administrative expense was higher in the first six months of 2001 because we recorded $1.3 million in additional employee benefit expenses for the present value of the separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. Our total interest expense is lower due to lower interest rates along with a substantial reduction in our long-term debt.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable

Item 2. Changes in Securities and Use of Proceeds

Not applicable

Item 3. Defaults Upon Senior Securities

Not applicable

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

On May 1, 2002 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 King P. Kirchner, Don Cook and J. Michael Adcock to serve as directors.

Nominee	Numbers of Votes For	Against or Withheld
King P. Kirchner	30,601,598	686,072
Don Cook	30,939,363	348,307
J. Michael Adcock	30,942,331	345,339

The following directors, whose term of office did not expire at the annual meeting, continue as directors of the Company: John G. Nikkel, John S. Zink, Earle Lamborn, William B. Morgan and John H. Williams.

II. Ratification of the appointment of PricewaterhouseCoopers L L P as the Company's independent certified public accountants for the fiscal year 2002.

For	-	30,976,301
Against	-	267,596
Abstain	-	43,773

Item 5. Other Information

Not applicable

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

15 Letter re: Unaudited Interim Financial Information.

(b) No reports on Form 8-K were filed during the quarter ended June 30, 2002.

SIGNATURES

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

UNIT CORPORATION

Date: August 9, 2002

By: /s/ John G. Nikkel

JOHN G. NIKKEL
President, Chief Executive Officer, Chief Operating Officer and Director

Date: August 9, 2002

By: /s/ Larry D. Pinkston

LARRY D. PINKSTON
Vice President, Chief Financial Officer and Treasurer