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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the fiscal year ended December 31, 1994

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

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 of Incorporation)	(I.R.S. Employer Identification No.)
1000 Kensington Tower 7130 South Lewis Tulsa, Oklahoma	74136
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, Including Area Code (918) 493-7700

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SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.20 per share	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Warrants to Purchase Shares of Common Stock

(Title of Class)

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in PART III of this Form 10-K or any amendment to this Form 10-K. X

Aggregate Market Value of the Voting Stock Held By
Non-affiliates on March 15, 1995 - $44,446,596

Number of Shares of Common Stock
Outstanding on March 15, 1995 - 20,933,190

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 3, 1995 are incorporated by reference in Part III.

Exhibit Index - See Page 66

Item 8. Financial Statements and Supplementary Data

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS	As of December 31, 1994	1993
	(In thousands)	
Current Assets:		
Cash and cash equivalents	$ 2,749	$ 3,756
Short-term investments	-	41
Accounts receivable (less allowance for doubtful accounts of $289 and $411)	16,369	14,099
Materials and supplies	1,498	1,424
Prepaid expenses and other	1,222	736
Total current assets	21,838	20,056
Property and Equipment:		
Drilling equipment	75,746	75,528
Oil and natural gas properties, on the full cost method	157,393	132,704
Transportation equipment	3,341	2,851
Other	7,925	8,541
	244,405	219,624
Less accumulated depreciation, depletion, amortization and impairment	153,862	144,099
Net property and equipment	90,543	75,525
Other Assets	40	181
Total Assets	$112,421	$ 95,762

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

LIABILITIES AND SHAREHOLDERS' EQUITY	As of December 31, 1994	1993
	(In thousands)	
Current Liabilities:		
Current portion of long-term debt	$ 496	$ 481
Current portion of natural gas purchaser prepayments (Note 4)	1,580	1,170
Accounts payable	14,593	14,008
Accrued liabilities	3,014	1,983
Contract advances	158	10
Total current liabilities	19,841	17,652
Natural Gas Purchaser Prepayments (Note 4)	2,149	4,417
Long-Term Debt	37,824	25,919
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	-	-
Common stock, $.20 par value, 40,000,000 shares authorized, 20,910,190 and 20,861,505 shares issued, respectively	4,182	4,172
Capital in excess of par value	50,086	49,977
Accumulated deficit	(1,581)	(6,375)
Treasury stock, at cost (25,100 shares)	(80)	-
Total shareholders' equity	52,607	47,774
Total Liabilities and Shareholders' Equity	$ 112,421	$ 95,762

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 1994	1993	1992
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$16,952	$14,676	$ 9,732
Oil and natural gas	26,001	24,073	23,464
Natural gas marketing and processing	44,171	32,104	21,970
Other	834	88	661

Total revenues	87,958	70,941	55,827
Expenses:			
Contract drilling:			
Operating costs	14,909	13,269	9,901
Depreciation and impairment	2,030	1,713	1,284
Oil and natural gas:			
Operating costs	8,799	8,098	7,538
Depreciation, depletion and amortization	8,281	7,018	7,128
Natural gas marketing and processing	43,897	32,325	22,627
General and administrative	3,574	3,302	3,114
Interest	1,654	1,324	1,633
Provision for litigation	-	-	1,500
Total expenses	83,144	67,049	54,725
Income Before Income Taxes	4,814	3,892	1,102
Income Tax Expense	20	21	15
Net Income	$ 4,794	$ 3,871	$ 1,087
Net Income Per Common Share	$ .23	$ .19	$ .05
Weighted Average Shares Outstanding (Both Primary and Fully Diluted)	20,900	20,860	20,781

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 1992, 1993 and 1994

	Common Stock	Capital In Excess Of Par Value	Accumulated Deficit	Treasury Stock	Total
			(In thousands)		
Balances, January 1, 1992	$ 4,143	$49,733	$(11,333)	$ -	$42,543
Net income	-	-	1,087	-	1,087
Activity in employee compensation plans (67,755 shares)	14	108	-	-	122
Balances, December 31, 1992	4,157	49,841	(10,246)	-	43,752
Net income	-	-	3,871	-	3,871
Activity in employee compensation plans (78,706 shares)	15	136	-	-	151
Balances, December 31, 1993	4,172	49,977	(6,375)	-	47,774
Net income	-	-	4,794	-	4,794
Activity in employee					

compensation plans (48,685 shares)	10	109	-	-	119
Purchase of treasury stock (25,100 shares)	-	-	-	(80)	(80)
Balances, December 31, 1994	$ 4,182	$50,086	$ (1,581)	$ (80)	$52,607

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 1994	1993	1992
	(In thousands)		
Cash Flows From Operating Activities:			
Net income	$ 4,794	$ 3,871	$ 1,087
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	10,774	9,256	8,772
Gain on disposition of assets	(813)	(49)	(463)
Employee stock compensation plans	119	151	122
Bad debt expense	-	-	200
Provision for litigation	-	-	1,500
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(939)	(1,257)	2,493
Materials and supplies	(74)	(99)	121
Prepaid expenses and other	(486)	83	191
Accounts payable	735	634	(747)
Accrued liabilities	760	(947)	(151)
Contract advances	148	8	(876)
Natural gas purchaser prepayments	(1,858)	(1,743)	(2,319)
Net cash provided by operating activities	13,160	9,908	9,930

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS - CONTINUED

	Year Ended December 31, 1994	1993	1992
		(In thousands)	
Cash Flows From Investing Activities:			
Capital expenditures (including producing property acquisitions)	$(28,227)	$(11,946)	$(10,768)
Proceeds from disposition of assets	2,038	709	1,146
Decrease in short-term investments	41	664	170
(Acquisition) disposition of other assets	141	(45)	60
Net cash used in investing activities	(26,007)	(10,618)	(9,392)
Cash Flows From Financing Activities:			
Borrowings under line of credit	63,700	43,400	23,900
Payments under line of credit	(51,300)	(40,600)	(24,700)
Proceeds from notes payable and other long-term debt	-	911	710
Payments on notes payable and other long-term debt	(480)	(367)	(80)
Acquisition of treasury stock	(80)	-	-
Net cash provided by (used in) financing activities	11,840	3,344	(170)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,007)	2,634	368
Cash and Cash Equivalents, Beginning of Year	3,756	1,122	754
Cash and Cash Equivalents, End of Year	$ 2,749	$ 3,756	$ 1,122
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest	$ 1,548	$ 1,326	$ 1,673
Income taxes	$ 2	$ 2	$ 63

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statements include the accounts of Unit Corporation and its directly and indirectly wholly owned subsidiaries (the

"Company"). The Company's investment in limited partnerships is accounted for on the proportionate consolidation method, whereby its share of the partnerships' assets, liabilities, revenues and expenses is included in the appropriate classification in the accompanying consolidated financial statements.

Drilling Contracts

The Company accounts for "footage" and "turnkey" drilling contracts, in which the Company assumes the risks associated with drilling the well, under the completed-contract method and for "daywork" drilling contracts under the percentage-of-completion method. The entire amount of the loss, if any, is recorded when the loss is determinable.

The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" drilling contracts which are still in process.

Cash Equivalents and Short-Term Investments

The Company includes as cash equivalents, certificates of deposits and all investments with original maturities at date of purchase of three months or less which are readily convertible into known amounts of cash.

Property and Equipment

Drilling equipment, transportation equipment and other property and equipment are carried at cost. The Company provides for depreciation of drilling equipment on the units-of-production method based on estimated useful lives, including a minimum provision of 20 percent of the active rate when the equipment is idle. At December 31, 1993, one of the Company's rigs was retired and certain components of the rig were written down by $160,000 to their estimated market value. The Company uses the composite method of depreciation for drill pipe and collars and calculates the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispo-

sitions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

Oil and Natural Gas Operations

The Company accounts for its oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the Securities and Exchange Commission ("SEC"). Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. The Company's determination of its oil and natural gas reserves are reviewed annually by independent petroleum engineers. The average composite rates used for depreciation, depletion and amortization ("DD&A") were $4.08, $4.13 and $4.67 per equivalent barrel in 1994, 1993 and 1992, respectively. The Company's calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs.

No gains or losses are recognized upon the sale, conveyance or other disposition of oil and natural gas properties unless a significant reserve amount is involved.

The SEC's full cost accounting rules prohibit recognition of income in current operations for services performed on oil and natural gas properties in which the Company has an interest or on properties in which a partnership, of which the Company is a general partner, has an interest. Accordingly, in 1994 the Company recorded $14,000 of contract drilling profits as a reduction of the carrying value of its oil and natural gas properties rather than including these profits in current operations. No contract drilling profits were realized on such interests in 1993 and 1992.

Limited Partnerships

The Company, through its wholly owned subsidiary, Unit Petroleum Company, is a general partner in eleven oil and natural gas limited partnerships sold privately and publicly. Certain of the Company's officers and directors own interests in some of these partnerships. Their interests were acquired generally on the same basis as other outside investors. Prior to December 31, 1993, the Company also was general partner of seven additional employee limited partnerships. However, pursuant to the terms of an agreement and plan of merger, these seven limited partnerships were consolidated into one new employee limited partnership effective December 31, 1993.

The Company shares in partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The

partnerships also reimburse the Company for certain administrative costs incurred on behalf of the partnerships.

Income Taxes

Income taxes are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes". SFAS No. 109 requires the measurement of deferred tax assets for deductible temporary differences and operating loss carryforwards, and of deferred tax liabilities for taxable temporary differences. Measurement of current and deferred tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Deferred tax assets primarily result from net operating loss carryforwards, and deferred tax liabilities result from the recognition of depreciation, depletion and amortization in different periods for financial reporting and tax purposes. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

Natural Gas Balancing

The Company uses the sales method for recording natural gas sales. This method allows for recognition of revenue which may be more or less than the Company's share of pro-rata production from certain wells. Based upon the Company's 1994 average spot market natural gas price of $1.65 per Mcf, the Company estimates its balancing position to be approximately $5.5 million on under-produced properties and approximately $3.1 million on over-produced properties.

The Company's policy is to expense its pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the Company's balancing position on wells on which the Company has imbalances are not material.

Financial Instruments and Concentrations of Credit Risk

At December 31, 1994, the Company had natural gas price swaps, related to its marketing of natural gas, which qualify as hedges of the Company's future purchase and sales commitments. Gains or losses on these swaps are recognized in the consolidated statement of operations and included in operating cash flows in the same period as the associated sale of natural gas occurs. At December 31, 1994, the Company had price swap agreements for 380,000 Mcf totaling $525,000 related to purchase commitments and 358,000 Mcf totaling $694,000 related to sales commitments for the period of January through March of 1995.

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trade receivables with a variety of national and international oil and natural gas companies. The Company does not generally require collateral related to receivables. Such credit risk is considered by management to be limited due to the large

number of customers comprising the Company's customer base. The Company had one customer in its natural gas marketing operation at December 31, 1993, with an accounts receivable balance of $4.1 million which was subsequently paid in January 1994. In addition, at December 31, 1994 and 1993, the Company had a concentration of cash of $2.3 and $3.4 million, respectively, with one bank.

RECLASSIFICATIONS

Certain reclassifications have been made in the 1992 and 1993 consolidated financial statements to conform them to classifications used in 1994.

NOTE 2 - PRODUCING PROPERTY ACQUISITION

On December 15, 1994, Unit Petroleum Company, a wholly owned subsidiary of Unit Corporation, acquired interests in approximately 700 oil and natural gas wells located primarily in Oklahoma, Texas, New Mexico and Louisiana. Financing for the transaction was provided under the Company's bank credit agreement. The acquisition is summarized as follows:

Current assets net of current liabilities	$ 976,000
Producing oil and natural gas properties	12,261,000
Net assets acquired	$13,237,000

Unaudited summary pro forma results of operations for the Company, reflecting the above described acquisition as if it had occurred at the beginning of the years ended December 31, 1994 and December 31, 1993, are as follows, respectively; revenues, $94,373,000 and $79,807,000; net income, $5,068,000 and $7,259,000; and net income per common share, $.24 and $.35. 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.

NOTE 3 - WARRANTS

In 1987, the Company issued 2.873 million units, consisting of three shares of the Company's common stock and one warrant, at a price of $10.375 per unit. Each warrant entitles the holder to purchase one share of the Company's common stock at a price of $4.375 anytime prior to the warrant's expiration on August 30, 1996. The warrants, subject to certain restrictions, are callable by the Company, in whole or in part, at $.50 per warrant. As of December 31, 1994 no warrants have been exercised.

NOTE 4 - NATURAL GAS PURCHASER PREPAYMENTS

In March 1988, the Company entered into a settlement agreement with a natural gas purchaser. During early 1991, the Company and the natural gas purchaser superseded the original agreement with a new settlement agreement effective retroactively to January 1, 1991. Under these settlement agreements, the Company has a prepayment balance of $3.7 million at

December 31, 1994 representing proceeds received from the purchaser as prepayment for natural gas. This amount is net of natural gas recouped and net of certain amounts disbursed to other owners (such owners, collectively with the Company are referred to as the "Committed Interest") for their proportionate share of the prepayments. The December 31, 1994 prepayment balance is subject to recoupment in volumes of natural gas for a period ending the earlier of recoupment or December 31, 1997 (the "Recoupment Period"). Additionally, the purchaser is obligated to make monthly payments on behalf of the Committed Interest in an amount calculated as a percentage of the Committed Interest's share of the deliverability of the wells subject to the settlement agreement, up to a maximum of $211,000 or a minimum of $110,000 per month for the year 1995. Both the maximum and minimum monthly payments decline annually through the Recoupment Period. At December 31, 1997, the Committed Interest's prepayment balance, if any, that has not been fully recouped in natural gas is subject to a cash repayment limited to a maximum of $3 million to be made in equal payments over a five year period. The prepayment amounts subject to recoupment from future production by the purchaser are being recorded as liabilities and are reflected in revenues as recoupment occurs. The portion of the prepayments that are estimated to be recouped in the next twelve months has been included in current liabilities. At the end of the Recoupment Period, the terms of the settlement agreement and the natural gas purchase contracts which are subject to the settlement agreement will terminate.

NOTE 5 - LONG-TERM DEBT

Long-term debt consisted of the following as of December 31, 1994 and 1993:

	1994	1993
	(In thousands)	
Revolving credit and term loan, with interest at December 31, 1994 and 1993 of 8.5% and 6%, respectively	$ 37,300	$ 24,900
Other	1,020	1,500
	38,320	26,400
Less current portion	496	481
Total long-term debt	$ 37,824	$ 25,919

At December 31, 1994, the Company's credit agreement ("Agreement") provided for a total loan commitment of $50 million consisting of a revolving credit facility through January 1, 1997 and a term loan thereafter, maturing on January 1, 2001. Borrowings under the Agreement are limited to a semi-annual borrowing base computation which as of December 31, 1994 is $42 million.

The principal of the revolving credit facility is due in 48 equal monthly payments commencing February 1, 1997 and continuing on the first day of each month thereafter through maturity. The outstanding principal amount of the revolving credit facility which is less than or equal to the loan value of the mineral interest then in effect shall bear interest at the Chase Manhattan Bank, N.A. prime rate ("Prime Rate") and that portion of the outstanding balance exceeding such loan value shall bear interest at the Prime Rate plus 1 and 1/2 percent through January 1, 1997. Subsequent to January 1, 1997 and continuing through January 1, 2001, the portion of the outstanding amount under the Agreement which is less than or equal to the loan value of the mineral interests then in effect shall bear interest at the Prime Rate plus 1/4 of 1 percent and any portion of the outstanding principal balance exceeding such loan value shall bear interest equal to the Prime Rate plus 1 and 1/2 percent. The Agreement also provides for a commitment fee of 1/2 of 1 percent of the unused portion of the borrowing base. Virtually all of the Company's drilling rigs are collateral for such indebtedness and the balance of the Company's assets are subject to a negative pledge.

The Agreement includes prohibitions against (i) the payment of dividends (other than stock dividends) during any fiscal year in excess of 25 percent of the consolidated net income of the Company during the preceding fiscal year, (ii) the incurrence by the Company or any of its subsidiaries of additional debt with certain very limited exceptions and (iii) the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any property of the Company or any of its subsidiaries, except in favor of its banks. The Agreement also requires that the Company maintain consolidated net worth of at least $45 million, a modified current ratio of not less than 1 to 1, a ratio of long-term debt, as defined in the Agreement, to consolidated tangible net worth not greater than 1 to 1 and a ratio of total liabilities, as defined in the Agreement, to consolidated tangible net worth not greater than 1.25 to 1. In addition, working capital provided by operations, as defined in the Agreement, cannot be less than $13 million in any year.

Estimated annual principal payments under the terms of all long-term debt from 1995 through 1999 are $496,000, $200,000, $200,000, $8,671,000 and $9,325,000.

NOTE 6 - INCOME TAXES

A reconciliation of the income tax expense, computed by applying the federal statutory rate to pre-tax income, to the Company's effective income tax expense is as follows:

	1994	1993	1992
		(In thousands)	
Income tax expense computed by applying the statutory rate	$ 1,637	$ 1,323	$ 375
Tax benefit of net operating loss carryforward	(1,652)	(1,308)	(396)
Alternative minimum tax	-	-	2
State income tax	6	1	7
Other	29	5	27
Income tax expense	$ 20	$ 21	$ 15

Deferred tax assets and liabilities are comprised of the following at December 31, 1994 and 1993:

	1994	1993
Deferred tax assets:	(In thousands)	
Allowance for losses	$ 521	$ 580
Gas purchaser prepayments	-	149
Net operating loss carryforwards	18,190	18,118
Statutory depletion carryforward	2,500	2,500
Investment tax credit carryforward	3,530	3,530
Gross deferred tax assets	24,741	24,877
Deferred tax liabilities:		
Depreciation, depletion and amortization	18,318	16,659
Gross deferred tax liabilities	18,318	16,659
Net deferred tax asset	6,423	8,218
Valuation allowance	6,423	8,218
	$ -	$ -

The net deferred tax asset valuation allowance reflects that the tax carryforwards above may not be utilized before the expiration dates as itemized below due in part to the effects of anticipated future exploratory and development drilling costs.

At December 31, 1994, the Company has net operating loss carryforwards for regular tax purposes of approximately $47,868,000 and net operating loss carryforwards for alternative minimum tax purposes of approximately

$38,260,000 which expire in various amounts from 1999 to 2007. The Company has investment tax credit carryforwards of approximately $3,530,000 which expire from 1995 to 2000. In addition, a statutory depletion carryforward of approximately $6,579,000 is available to reduce future taxable income, subject to statutory limitations. Statutory depletion may be carried forward indefinitely.

In 1987, the Company completed an equity offering which constituted an ownership change as that term is used in the Internal Revenue Code. As a result of the ownership change, the amount of taxable income in future years which may be offset by the Company's net operating loss carryovers prior to the ownership change is limited. Tax losses of $45,950,000 at December 31, 1994 are not subject to these limitations. The remaining tax net operating loss carryforward will become available for utilization by the Company at a rate of $3,500,000 per year. Similar limitations apply to investment tax credits.

NOTE 7 - BENEFIT AND COMPENSATION PLANS

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan ("the Plan") whereby 330,950 shares of common stock were authorized for issuance under the Plan. Under the terms of the Plan, bonuses may be granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in annual installments subject to certain restrictions. The Company issued 38,354 and 50,788 shares under the Plan in 1993 and 1992, respectively. No shares were issued under the Plan in 1994.

The Company has a Stock Option Plan which provides for the granting of options for up to 1,000,000 shares of common stock to officers and employees. The plan permits the issuance of qualified or nonqualified stock options. Stock options granted in 1986 became exercisable at the rate of 20 percent per year through 1990. Options granted subsequent to 1986 become exercisable at the rate of 20 percent per year one year after being granted.

Activity pertaining to the Stock Option Plan is as follows:

	NUMBER OF SHARES	OPTION PRICE

	NUMBER OF SHARES	PER SHARE	AGGREGATE
Outstanding at January 1, 1992	752,000	$1.50 to 3.375	$1,476,995
Granted	10,000	1.875	18,750
Cancelled	(10,000)	2.37 to 2.875	(26,225)
Outstanding at December 31, 1992	752,000	1.50 to 3.375	1,469,520
Granted	89,000	2.75	244,750
Exercised	(12,000)	1.50 to 2.37	(19,740)
Outstanding at December 31, 1993	829,000	1.50 to 3.375	1,694,530
Granted	102,500	3.00	307,500
Exercised	(16,000)	1.50 to 2.37	(24,870)
Outstanding at December 31, 1994	915,500	$1.50 to 3.375	$ 1,977,160

Options for 676,400, 610,500 and 556,400 shares were exercisable at prices ranging from $1.50 to $3.375 at December 31, 1994, 1993 and 1992, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Directors' Plan"). An aggregate of 100,000 shares of the Company's common stock may be issued or delivered upon exercise of the stock options. On the first business day following each annual meeting of stockholders of the Company, each person who is then a member of the Board of Directors of the Company and who is not then an employee of the Company or any of its subsidiaries will be granted an option to purchase 2,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. No stock options may be exercised during the first six months of its term except in case of death and no stock options are exercisable after ten years from the date of grant.

Activity pertaining to the Directors' Plan is as follows:

	NUMBER OF SHARES	OPTION PRICE	
		PER SHARE	AGGREGATE
1992:			
Granted	10,000	$ 1.75	$ 17,500
Outstanding at December 31, 1992	10,000	1.75	17,500
Granted	10,000	3.75	37,500
Outstanding at December 31, 1993	20,000	1.75 to 3.75	55,000
Granted	10,000	2.875	28,750
Outstanding at December 31, 1994	30,000(1)	$1.75 to 3.75	$ 83,750

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(1) All 30,000 options were exercisable at December 31, 1994.

Under the Company's 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. Each employee's contribution, up to a specified maximum, may be matched by the Company in full or on a partial basis. The Company made discretionary contributions under the plan of 32,685, 28,352 and 16,967 shares of common stock and recognized expense of $130,000, $162,000 and $33,000 in 1994, 1993 and 1992, respectively.

Effective March 1, 1993, the Company adopted a salary deferral plan ("Deferral Plan"). The Deferral Plan 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. Funds set aside in a trust to satisfy the Company's obligation under the Deferral Plan at December 31, 1994 and 1993 totaled $108,000 and $41,000, respectively. The Company recognizes payroll expense and records a deferred liability at the time of deferral.

NOTE 8 - TRANSACTIONS WITH RELATED PARTIES

The Company formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 1994, with a subsidiary of the Company 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 the Company in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with the Company in most drilling operations and most producing property

acquisitions commenced by the Company for its own account during the period from the formation of the Partnership through December 31 of each year. Pursuant to the terms of an agreement and plan of merger, seven limited partnerships, in which the Company was general partner, were consolidated into one new employee limited partnership effective December 31, 1993.

Amounts received in the following years ended December 31 from both public and private Partnerships for which the Company is a general partner are as follows:

	1994	1993	1992
		(In thousands)	
Contract drilling	$ 53	$ 60	$ 38
Well supervision and other fees	$ 226	$ 278	$ 277
General and administrative expense reimbursement	$ 209	$ 231	$ 294

A subsidiary of the Company paid the Partnerships, for which the Company or a subsidiary is the general partner, $38,000, $65,000 and $58,000 during the years ended December 31, 1994, 1993 and 1992, respectively, for purchases of natural gas production.

During 1993 and 1992, the Company received legal services from a law firm of which one of the Company's directors was a partner. Total payments to the law firm during 1993 and 1992 were $164,000 and $130,000, respectively. The Company did not receive such services from the law firm in 1994.

During 1994, a bank owned by one of the Company's Directors became a participant in the Company's loan agreement. The bank's total pro rata share of the Company's line of credit is not to exceed $1.5 million.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

The Company is currently negotiating a new operating lease agreement to remain in its current office space until February 1, 2000. Future minimum rental payments under the proposed terms of the lease would be approximately $205,000, $224,000, $244,000, $246,000 and $246,000 in 1995, 1996, 1997, 1998 and 1999, respectively. Total rent expense incurred by the Company was $210,000, $208,000 and $205,000 in 1994, 1993 and 1992, respectively.

The Company had letters of credit totaling $835,600 outstanding at December 31, 1994.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, upon the election of a limited partner, that the Company repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20 percent of the units outstanding. The Company made

repurchases of $38,000, $56,000 and $70,000 in 1994, 1993 and 1992, respectively, for such limited partner's interest.

The Company is a party to a settlement agreement dated January 31, 1991 with a natural gas purchaser which superseded a settlement agreement entered into during March of 1988. Under the agreements the purchaser made certain prepayments to the Company for natural gas to be delivered to the purchaser in the future. As of December 31, 1994, this prepayment balance for natural gas yet to be delivered was $3.7 million. The Company has learned that the Oklahoma Tax Commission (the "Commission"), based on four assessments, one in 1988, one in 1992 and two in 1994, is seeking to hold the purchaser liable for certain taxes, interests and penalties that the Commission contends are due and owing with respect to the prepayment amounts made by the purchaser under the agreements on the grounds that the prepayments are solely attributable to the settlement of past claims for take-or-pay obligations. To date, the Company is not a party to the Commission's proceedings, but may in the future, seek to intervene in these proceedings. The purchaser has denied the claims made by the Commission and is contesting the assessments. The purchaser and the Commission have settled the 1988 assessment for approximately $51,000 and the remaining three assessments have been consolidated and set for a hearing before an administrative law judge on or before May 10, 1995. The purchaser has notified the Company of the proceedings and has indicated its intention to assert claims against the Company to recover the amount it paid in settlement of the 1988 assessment (including its attorney fees) as well as any amounts it might have to pay by virtue of the remaining assessments. The Company is aware that the purchaser has made such claims against other companies which also received prepayments from the purchaser, although the type of agreements and the facts involved in those cases are not known by the Company. At this time, the Company is unable to determine what the outcome of the remaining Commission's proceedings will be, the amount of taxes, if any, plus interest and penalties that may ultimately be assessed against the purchaser and the claims, if any, that the purchaser might seek to assert against the Company in the event an unfavorable result is incurred by the purchaser. The Company has advised the purchaser that it believes the responsibility for the payment of the taxes, interest and penalty sought by the Commission, should it be ultimately determined that any such amounts are in fact owed, is the responsibility of the purchaser and not the Company.

The Company is a party to various legal proceedings arising in the ordinary course of its business none of which, in the Company's opinion, should result in judgements which would have a material adverse effect on the Company.

NOTE 10 - INDUSTRY SEGMENT INFORMATION

The Company operates in the United States in three industry segments which are contract drilling, oil and natural gas exploration and production and natural gas marketing and processing. The Company also has natural gas production in Canada which is not significant. Selected financial information by industry segment is as follows:

	Operating Revenues	Operating Profit (Loss)(1)	Total Assets(2)	Capital Expenditures	Depreciation, Depletion, Amortization and Impairment Expense
	(In thousands)				
Year ended December 31, 1994:					
Drilling	$ 16,952	$ 13	$ 14,771	$ 1,115	$ 2,030
Oil and natural gas	26,001	8,921	83,082	25,110	8,281
Natural gas marketing and processing	44,171	274	10,619	56	331
	87,124	$ 9,208	108,472	26,281	10,642
Other	834		3,949	708	132
Total	$ 87,958		$112,421	$ 26,989	$ 10,774
Year ended December 31, 1993:					
Drilling	$ 14,676	$ (306)	$ 15,738	$ 936	$ 1,713
Oil and natural gas	24,073	8,957	64,845	11,422	7,018
Natural gas marketing and processing	32,104	(221)	10,099	1,049	418
	70,853	$ 8,430	90,682	13,407	9,149
Other	88		5,080	323	107
Total	$ 70,941		$ 95,762	$ 13,730	$ 9,256
Year ended December 31, 1992:					
Drilling	$ 9,732	$(1,453)	$ 16,382	$ 266	$ 1,284
Oil and natural gas	23,464	8,798	61,694	7,951	7,128
Natural gas marketing and processing	21,970	(657)	7,628	541	250
	55,166	$ 6,688	85,704	8,758	8,662
Other	661		3,006	137	110
Total	$ 55,827		$ 88,710	$ 8,895	$ 8,772

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

(2) Identifiable assets are those used in the Company's operations in each industry segment. Corporate assets are principally cash and cash equivalents, short-term investments, corporate leasehold improvements and furniture and equipment.

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 1994 and 1993 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year ended December 31, 1994:				
Revenues	$ 23,005	$ 19,926	$ 21,166 (2)	$ 23,861
Gross Profit(1)	$ 2,396	$ 2,726	$ 2,090	$ 1,996
Income before income taxes	$ 1,215	$ 1,430	$ 1,595 (2)	$ 574
Net income	$ 1,211	$ 1,425	$ 1,590 (2)	$ 568
Net income per common share	$ .06	$ .07	$ .07 (2)	$ .03
Year ended December 31, 1993:				
Revenues	$ 15,574	$ 17,881	$ 16,935	$ 20,551
Gross Profit(1)	$ 2,357	$ 1,982	$ 1,920	$ 2,171
Income before income taxes	$ 1,163	$ 884	$ 890	$ 955
Net income	$ 1,156	$ 878	$ 886	$ 951
Net income per common share	$ 0.06	$ 0.04	$ 0.04	$ 0.05

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(1) Gross Profit excludes other revenues, general and administrative

expense and interest expense.

(2) Includes $742,000 net gain on sale of natural gas gathering system.

NOTE 12 - OIL AND NATURAL GAS INFORMATION (UNAUDITED)

The capitalized costs at year end and costs incurred during the year were as follows:

	USA	Canada	Total
		(In thousands)	
1994:			
Capitalized costs:			
Proved properties	$ 154,688	$ 455	$155,143
Unproved properties	2,250	-	2,250
	156,938	455	157,393
Less accumulated depreciation, depletion, amortization and impairment	81,583	368	81,951
Net capitalized costs	$ 75,355	$ 87	$ 75,422
Cost incurred:			
Unproved properties	$ 460	$ -	$ 460
Producing properties	13,108	-	13,108
Exploration	1,825	-	1,825
Development	9,716	1	9,717
Total costs incurred	$ 25,109	$ 1	$ 25,110
1993:			
Capitalized costs:			
Proved properties	$ 129,612	$ 454	$130,066
Unproved properties	2,638	-	2,638
	132,250	454	132,704
Less accumulated depreciation, depletion, amortization and impairment	73,419	314	73,733
Net capitalized costs	$ 58,831	$ 140	$ 58,971
Cost incurred:			
Unproved properties	$ 732	$ -	$ 732
Producing properties	1,241	-	1,241
Exploration	1,359	-	1,359
Development	8,084	6	8,090
Total costs incurred	$ 11,416	$ 6	$ 11,422

	USA	Canada	Total
	(In thousands)		
1992:			
Capitalized costs:			
Proved properties	$ 117,721	$ 448	$ 118,169
Unproved properties	3,680	-	3,680
	121,401	448	121,849
Less accumulated depreciation, depletion, amortization and impairment	66,544	233	66,777
Net capitalized costs	$ 54,857	$ 215	$ 55,072
Cost incurred:			
Unproved properties	$ 504	$ -	$ 504
Producing properties	3,629	-	3,629
Exploration	900	-	900
Development	2,918	-	2,918
Total costs incurred	$ 7,951	$ -	$ 7,951

The results of operations before income taxes for producing activities are provided below. Due to the Company's utilization of net operating loss carryforwards, income taxes are not significant and have not been included.

	USA	Canada	Total
	(In thousands)		
1994:			
Revenues	$ 23,964	$ 67	$ 24,031
Production costs	7,011	19	7,030
Depreciation, depletion and amortization	8,165	53	8,218
Results of operations for producing activities before income taxes (excluding corporate overhead and financing costs)	$ 8,788	$ (5)	$ 8,783

	USA	Canada	Total
	(In thousands)		
1993:			
Revenues	$ 22,040	$ 67	$ 22,107
Production costs	6,439	15	6,454
Depreciation, depletion and amortization	6,875	81	6,956
Results of operations for producing activities before income taxes (excluding corporate overhead and financing costs)	$ 8,726	$ (29)	$ 8,697
1992:			
Revenues	$ 21,816	$ 75	$ 21,891
Production costs	6,159	10	6,169

Depreciation, depletion and amortization	6,961	94	7,055
Results of operations for producing activities before income taxes (excluding corporate overhead and financing costs)	$ 8,696	$ (29)	$ 8,667

Estimated quantities of proved developed oil and natural gas reserves and changes in net quantities of proved developed and undeveloped oil and natural gas reserves were as follows:

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
			(In thousands)			
1994:						
Proved developed and undeveloped reserves:						
Beginning of year	3,304	71,379	-	861	3,304	72,240
Revision of previous estimates	(97)	(571)	-	(14)	(97)	(585)
Extensions, discoveries and other additions	601	17,426	-	-	601	17,426
Purchases of minerals in place	910	14,075	-	-	910	14,075
Sales of minerals in place	(4)	(137)	-	-	(4)	(137)
Production	(406)	(9,606)	-	(53)	(406)	(9,659)
End of Year	4,308	92,566	-	794	4,308	93,360
Proved developed reserves:						
Beginning of year	3,187	65,395	-	426	3,187	65,821
End of year	3,521	80,110	-	359	3,521	80,469
1993:						
Proved developed and undeveloped reserves:						
Beginning of year	3,308	63,761	-	931	3,308	64,692
Revision of previous estimates	(132)	4,662	-	-	(132)	4,662
Extensions, discoveries and other additions	549	9,169	-	-	549	9,169
Purchases of minerals						

in place	18	1,369	-	-	18	1,369
Sales of minerals in place	(42)	(147)	-	-	(42)	(147)
Production	(397)	(7,435)	-	(70)	(397)	(7,505)
End of Year	3,304	71,379	-	861	3,304	72,240
Proved developed reserves:						
Beginning of year	3,245	58,809	-	468	3,245	59,277
End of year	3,187	65,395	-	426	3,187	65,821

	USA		Canada		Total	
	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
1992:			(In Thousands)			
Proved developed and undeveloped reserves:						
Beginning of year	2,943	52,853	-	964	2,943	53,817
Revision of previous estimates	235	7,679	-	47	235	7,726
Extensions, discoveries and other additions	190	1,655	-	-	190	1,655
Purchases of minerals in place	316	8,327	-	-	316	8,327
Sales of minerals in place	(1)	(23)	-	-	(1)	(23)
Production	(375)	(6,730)	-	(80)	(375)	(6,810)
End of Year	3,308	63,761	-	931	3,308	64,692
Proved developed reserves:						
Beginning of year	2,778	44,936	-	499	2,278	45,435
End of year	3,245	58,809	-	468	3,245	59,277

Oil and natural gas reserves cannot be measured exactly. Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in connection with financial disclosures. The Company utilizes Ryder Scott Company, independent petroleum consultants, to review the Company's reserves as prepared by the Company's reservoir engineers.

Proved reserves are those quantities which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data as explained above. 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. The information set forth herein is therefore subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves nor of estimated future cash flows.

The standardized measure of discounted future net cash flows ("SMOG") was calculated using year-end prices and costs, and year-end statutory tax rates, adjusted for permanent differences, that relate to existing proved oil and natural gas reserves. SMOG as of December 31 is as follows:

	USA	Canada	Total
		(In thousands)	
1994:			
Future cash flows	$234,171	$ 1,255	$235,426
Future production and development costs	105,876	311	106,187
Future income tax expenses	20,161	524	20,685
Future net cash flows	108,134	420	108,554
10% annual discount for estimated timing of cash flows	30,116	170	30,286
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 78,018	$ 250	$ 78,268
1993:			
Future cash flows	$214,800	$ 861	$215,661
Future production and development costs	90,177	229	90,406
Future income tax expenses	17,097	244	17,341
Future net cash flows	107,526	388	107,914
10% annual discount for estimated timing of cash flows	34,374	157	34,531
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 73,152	$ 231	$ 73,383
1992			
Future cash flows	$208,964	$ 931	$209,895
Future production and development costs	86,417	361	86,778
Future income tax expenses	19,634	194	19,828
Future net cash flows	102,913	376	103,289
10% annual discount for estimated timing of cash flows	32,653	120	32,773
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 70,260	$ 256	$ 70,516

The principal sources of changes in the standardized measure of discounted future net cash flows were as follows:

	USA	Canada	Total
		(In thousands)	
1994:			
Sales and transfers of oil and natural gas produced, net of production costs	$(16,953)	$ (48)	$(17,001)
Net changes in prices and production costs	(14,941)	206	(14,735)
Revisions in quantity estimates and changes in production timing	(482)	(5)	(487)
Extensions, discoveries and improved recovery, less related costs	17,050	-	17,050

Purchases of minerals in place	13,426	-	13,426
Sales of minerals in place	(138)	-	(138)
Accretion of discount	7,915	35	7,950
Net change in income taxes	(457)	(177)	(634)
Other - net	(554)	8	(546)
Net change	4,866	19	4,885
Beginning of year	73,152	231	73,383
End of year	$ 78,018	$ 250	$ 78,268
1993:			
Sales and transfers of oil and natural gas produced, net of production costs	$(15,359)	$ (52)	$(15,411)
Net changes in prices and production costs	(4,997)	73	(4,924)
Revisions in quantity estimates and changes in production timing	483	(70)	413
Extensions, discoveries and improved recovery, less related costs	12,886	-	12,886
Purchases of minerals in place	1,440	-	1,440
Sales of minerals in place	(284)	-	(284)
Accretion of discount	7,619	36	7,655
Net change in income taxes	(74)	(8)	(82)
Other - net	1,178	(4)	1,174
Net change	2,892	(25)	2,867
Beginning of year	70,260	256	70,516
End of year	$ 73,152	$ 231	$ 73,383

	USA	Canada	Total
		(In Thousands)	
1992:			
Sales and transfers of oil and natural gas produced, net of production costs	$(14,693)	$ (65)	$(14,758)
Net changes in prices and production costs	(1,081)	(117)	(1,198)
Revisions in quantity estimates and changes in production timing	4,113	2	4,115
Extensions, discoveries and improved recovery, less related costs	3,677	-	3,677
Purchases of minerals in place	9,488	-	9,488
Sales of minerals in place	(47)	-	(47)
Accretion of discount	6,602	49	6,651
Net change in income taxes	(2,870)	95	(2,775)
Other - net	2,104	5	2,109
Net change	7,293	(31)	7,262
Beginning of year	62,967	287	63,254
End of year	$ 70,260	$ 256	$ 70,516

The Company's SMOG and changes therein were determined in accordance with Statement of Financial Accounting Standards No. 69. Certain information concerning the assumptions used in computing SMOG and their inherent limitations are discussed below. Management believes such information is essential for a proper understanding and assessment of the data presented.

The assumptions used to compute SMOG do not necessarily reflect management's expectations of actual revenues to be derived from those reserves nor their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of such reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to errors inherent in predicting the future, variations from the expected production rate could result from factors outside of management's control, such as unintentional delays in development, environmental concerns or changes in prices or regulatory controls. Also, the reserve valuation assumes that all reserves will be disposed of by production. However, other factors such as the sale of reserves in place could affect the amount of cash eventually realized.

Future cash flows are computed by applying year-end prices of oil and natural gas relating to proved reserves to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at the end of the year, based on continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the future pretax net cash flows relating to proved oil and natural gas reserves less the tax basis of the Company's properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to the Company's proved oil and natural gas reserves.

Care should be exercised in the use and interpretation of the above data. As production occurs over the next several years, the results shown may be significantly different as changes in production performance, petroleum prices and costs are likely to occur.

As disclosed in Note 4, the Company is receiving payments from a natural gas purchaser which are subject to recoupment from future natural gas production. The amounts received will be reflected in revenues and the reserves and future net cash flows will be reduced as recoupment occurs.

Subsequent to December 31, 1994, the natural gas industry experienced a significant downturn in natural gas prices. The Company's reserves were determined at December 31, 1994 using a natural gas price of approximately $1.70 per Mcf for natural gas not subject to long-term contracts. At February 21, 1995, the natural gas prices received by the Company fell to approximately $1.41 per Mcf for natural gas not subject to long-term contracts. This decrease in natural gas prices would have had a significant effect on the SMOG value of the Company's reserves at December 31, 1994 and would have resulted in a provision to reduce the carrying value of oil and natural gas properties of approximately $3.5 million.

REPORT OF INDEPENDENT ACCOUNTANTS

The Shareholders and Board of Directors
Unit Corporation

We have audited the accompanying consolidated balance sheets of Unit Corporation and subsidiaries as of December 31, 1994 and 1993 and the related consolidated statements of operations, changes in shareholders' equity and cash flows and the related financial statement schedule for each of the three years in the period ended December 31, 1994. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unit Corporation and subsidiaries as of December 31, 1994 and 1993, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1994 in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information required to be included therein.

COOPERS & LYBRAND L.L.P.

Tulsa, Oklahoma
February 22, 1995

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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: March 30, 1995 By: /s/ Larry D. Pinkston

LARRY D. PINKSTON
Vice President and Chief Financial

Officer and Treasurer