F O R M 1 0-K

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, 2002

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

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**

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. ___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes _X_ No ___

Aggregate Market Value of the Voting Stock Held By Non-affiliates on June 30, 2002 - $420,961,714

Number of Shares of Common Stock Outstanding on March 7, 2003 - 43,514,317

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 7, 2003 are incorporated by reference in Part III.

Exhibit Index - See Page 100

FORM 10-K
UNIT CORPORATION

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2002

PART I

Item 1. ***Business* and Item 2.** ***Properties***

OUR BUSINESS

Through our wholly owned subsidiaries, we

- contract to drill onshore oil and natural gas wells for others and
- explore, develop, acquire and produce oil and natural gas properties for our self.

We were founded in 1963 as a contract drilling company.

Our executive offices are at 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700. We also have regional offices in Oklahoma City, Oklahoma, Woodward, Oklahoma, Booker, Texas, Houston, Texas and Casper, Wyoming.

Our primary Internet address is www.unitcorp.com. We make our periodic SEC Reports (Forms 10-Q and Forms 10-K) and current reports (Form 8-K) available free of charge through our Web site as soon as reasonably practicable after they are filed electronically with the SEC. We may from time to time provide important disclosures to investors by posting them in the investor relations section of our Web site, as allowed by SEC rules.

Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet Web site at www.sec.gov that contains reports, proxy and information statements, and other information regarding our company that we file electronically with the SEC.

When used in this report, the terms Corporation, Unit, our, we and its refer to Unit Corporation and, as appropriate, Unit Corporation and/or one or more of its subsidiaries.

OUR LAND CONTRACT DRILLING BUSINESS

General. Using our 75 drilling rigs, our wholly owned subsidiary, Unit Drilling Company, drills onshore natural gas and oil wells for a wide range of customers. Our drilling operations are mainly in the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Cost and in the East Texas and Rocky Mountain regions.

The following table sets forth, for each of the periods indicated, certain information concerning our contract drilling operations:

	Year Ended December 31,				
	1998	**1999**	**2000**	**2001**	**2002**
Number of Rigs Owned at End of Period	34.0	47.0	50.0	55.0	75.0
Average Number of Rigs Owned During Period	34.0	37.3	47.0	51.8	61.6
Average Number of Rigs Utilized	22.9	23.1	39.8	46.3	39.1
Utilization Rate (2)	67%	62%	85%	90%	63%
Average Revenue Per Day (3)	$6,394	$6,582	$7,432	$9,879	$8,285
Total Footage Drilled (Feet in 1000's)	2,203	2,211	3,650	4,008	3,829
Number of Wells Drilled	198	197	316	361	318

(1) Includes 20 rigs acquired in August 2002.

(2) We determine our utilization rate on a 365 day year by dividing the number of rigs used by our total number of rigs.

(3) Represents total revenues from contract drilling operations divided by the total number of days rigs were used during the period.

Acquisitions. On August 15, 2002 we acquired twenty drilling rigs, spare drilling equipment and vehicles when we acquired CREC Rig Equipment Company and CDC Drilling Company. We issued 6,819,748 shares of common stock and paid $3,813,053 for all the outstanding shares of CREC Rig Acquisition Company and issued 400,252 shares of common stock and paid $686,947 for all the outstanding shares of CDC Drilling Company. The twenty rigs range in horsepower from 650 to 2,000 with 15 having a horsepower rating of 1,000 or more. Twelve of the rigs are SCR electric. Depth capacities range from 12,000 to 25,000 feet.

Description of our Drilling Rigs. A land drilling rig consists, in part, of engines, drawworks or hoists, derrick or mast, substructure, pumps to circulate the drilling fluid, blowout preventers and drill pipe. Over the life of a typical rig, due to the normal wear and tear of operating 24 hours a day, several of the major components, such as engines, mud pumps and drill pipe, must be replaced or rebuilt on a periodic basis, while other components, such as the substructure, mast and drawworks, can be used for extended periods of time with proper maintenance. We also own additional equipment used in the operation of our rigs, including large air compressors, trucks and other support equipment.

Our rigs have maximum depth capacities ranging from 9,500 to 40,000 feet.

The following table shows the current distribution of our rigs as of March 7, 2003:

Region	Active Rigs(1)	Idle Rigs(1)	Total Rigs	Average Rated Drilling Depths(ft)
Anadarko Basin	35	6	41	16,000
West Texas	-	2	2	20,000
Arkoma Basin	6	1	7	17,000
East Texas and Gulf Coast	11	6	17	19,000
Rocky Mountains	3	5	8	22,000

(1) A rig is active when under contract. An idle rig is one that is not under contract but is available and marketed.

At present, we do not have a shortage of drilling rig related equipment. However, at any given time, our ability to use all of our rigs is dependent on a number of conditions, including the availability of qualified labor, drilling supplies and equipment as well as demand.

Types of Drilling Contracts We Work Under. Our drilling contracts are predominantly obtained through competitive bidding and are for a single well. Terms and payment rates vary depending on the nature and duration of the work, the equipment and services supplied and other matters. We pay certain operating expenses, including wages of drilling personnel, maintenance expenses and incidental rig supplies and equipment. Usually the contracts are subject to termination by the customer on short notice upon payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property and for acts of pollution. The specific terms of these indemnifications are subject to negotiation on a contract by contract basis.

The type of contract used determines our compensation. The contracts are generally one of three types: daywork; footage; or turnkey. Additional compensation may be acquired for special risks and unusual conditions. Under daywork contracts we provide the drilling rig with the required personnel to the operator who then supervises the drilling of the well. Our compensation depends on a negotiated rate for each day of the rig’s use. Footage contracts usually require us to bear some of the drilling costs in addition to providing the rig. We are paid on a negotiated per foot drilled rate on completion of the well. Under turnkey contracts we contract to drill the well for a lump sum amount to a specified depth and provide most of the equipment and services required. We bear the risk of drilling the well to the contract depth and are paid when the contract provisions are completed.

Under turnkey contracts we may incur losses if we underestimate the costs to drill the well or if unforeseen events occur. To date, we have not experienced significant losses in performing turnkey contracts. In 2002, we drilled 15 turnkey wells and turnkey revenue represented 4 percent of our contract drilling revenues as compared to one percent for 2001. We had one turnkey contract in progress at December 31, 2002. Because market conditions as well as the desires of our customers determine the use of turnkey contracts, we can't predict whether the portion of drilling conducted on a turnkey basis will increase or decrease in the future.

Customers. During 2002, 10 customers accounted for approximately 43 percent of our total contract drilling revenues. Approximately 4 percent of our contract drilling revenues came from drilling operations we conducted on oil and natural gas properties of which we were the operator (including properties owned by limited partnerships for which we acted as general partner).

Additional Information. Further information relating to contract drilling operations can be found in Notes 1, 2 and 10 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

OUR OIL AND NATURAL GAS BUSINESS

General. In 1979 we began to develop our exploration and production operations to diversify our contract drilling revenues. Today, our wholly owned subsidiary, Unit Petroleum Company, conducts our exploration and production activities. Our producing oil and natural gas properties, undeveloped leaseholds and related assets are mainly in Oklahoma, Texas, Louisiana and New Mexico and, to a lesser extent, in Arkansas, North Dakota, Colorado, Wyoming, Montana, Alabama, Mississippi, Illinois, Michigan, Nebraska and Canada.

When we are the operator of a property, we generally employ our own drilling rigs.

Well and Leasehold Data. The tables below set forth certain information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31,					
	2000		2001		2002	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploratory:						
Oil	-	-	1	.01	-	-
Natural gas	2	1.63	8	3.60	2	.50
Dry	-	-	5	4.46	5	2.00
	2	1.63	14	8.07	7	2.50
Development:						
Oil	7	1.45	6	1.06	4	1.91
Natural gas	75	28.51	87	33.51	68	33.25
Dry	17	8.56	18	10.80	17	14.21
	99	38.52	111	45.37	89	49.37
Total	101	40.15	125	53.44	96	51.87

	Year Ended December 31,					
	2000		2001		2002	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil and Natural Gas Wells Producing or Capable of Producing:						
Oil - USA	799	278.06	786	279.06	790	273.34
Oil - Canada	-	-	-	-	-	-
Gas - USA	2,088	431.11	2,188	457.38	2,449	524.45
Gas - Canada	64	1.60	64	1.60	65	1.63
Total	2,951	710.77	3,038	738.04	3,304	799.42

In December 2002, we acquired 73 producing oil and natural gas wells for $12.5 million. The properties are in Hemphill County, Texas.

On March 7, 2003, we were participating in the drilling of 7 gross (2.1304 net) wells in the United States.

The following table summarizes our oil and natural gas leasehold acreage for each of the years indicated:

	Developed Acreage		Undeveloped Acreage	
	Gross	**Net**	**Gross**	**Net**
2000:				
USA	564,780	153,507	61,487	39,480
Canada	39,040	976	26,243	13,121
Total	603,820	154,483	87,730	52,601
2001:				
USA	567,731	155,890	110,489	69,229
Canada	39,040	976	7,273	3,636
Total	606,771	156,866	117,762	72,865
2002:				
USA	585,313	166,397	142,764	79,911
Canada	39,040	976	5,441	3,360
Total	624,353	167,373	148,205	83,271

Price and Production Data. The following table sets forth our average sales price, oil and natural gas production volumes and average production cost per equivalent Mcf [1 barrel (Bbl) of oil = 6 thousand cubic feet (Mcf) of natural gas] of production for the years indicated:

	Year Ended December 31,		
	2000	**2001**	**2002**
Average Sales Price per Barrel of Oil Produced:			
USA	$ 26.95	$ 23.62	$ 21.54
Canada	-	-	-
Average Sales Price per Mcf of Natural Gas Produced:			
USA	$ 3.91	$ 4.00	$ 2.87
Canada	$ 2.39	$ 4.21	$ 2.11
Oil Production (Mbbls):			
USA	488	492	473
Canada	-	-	-
Total	488	492	473
Natural Gas Production (MMcf):			
USA	19,239	18,819	18,927
Canada	46	45	41
Total	19,285	18,864	18,968
Average Production Expense per Equivalent Mcf:			
USA	$ 0.74	$ 0.86	$ 0.79
Canada	$ 0.42	$ 0.51	$ 0.60

Oil and Natural Gas Reserves. The following table sets forth our estimated proved developed and undeveloped oil and natural gas reserves for each of the years indicated:

	Year Ended December 31,		
	2000	**2001**	**2002**
Oil (Mbbls):			
USA	4,183	4,343	4,096
Canada	-	-	-
Total	4,183	4,343	4,096
Natural gas (MMcf):			
USA	215,196	227,865	244,494
Canada	441	389	317
Total	215,637	228,254	244,811

Our oil production is sold at or near our wells under purchase contracts at prevailing prices in accordance with arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms under contracts with terms ranging from one month to a year. The longer term contracts contain provisions for price adjustments. Most of these contracts contain provisions for readjustment of price, termination and other terms customary in the industry.

Additional Information. Further information relating to oil and natural gas operations can be found in Notes 1 and 10 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for natural gas and oil significantly affect our revenues, operating results, cash flow and future rate of growth. Because natural gas makes up the biggest part of our oil and natural gas reserves as well as the focus of most of our drilling work we do for others, changes in natural gas prices have a disproportionate impact on our financial results than do oil price changes. Historically, oil and natural gas prices have been volatile, and we expect that they will continue to be volatile. Oil and natural gas prices increased substantially in the last half of 1999 and throughout 2000 into the first quarter of 2001. Prices then started to decline sharply and by February 2002, our average price for natural gas was $1.87 per Mcf and our average oil price was $15.58. Commodity prices have once again increased and the average natural gas price we received in

December 2002 was $3.95 and the average oil price we received was $25.59. Our average natural gas and oil price for 2002 was $2.87 and $21.54, respectively.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- the domestic and foreign supply of oil and natural gas;
- the level of consumer demand;
- United States storage levels of natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil and natural gas.

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. Decreased oil and natural gas prices during 1998 and early 1999 adversely affected our contract drilling activity by lowering the demand for our rigs and reducing the rates we were able to charge. With the increase in oil and natural gas prices starting in the last half of 1999 and continuing through January 2001, our dayrates and rig utilization increased substantially. Due to the fall in natural gas prices which started in February, 2001, we began to experience less demand for our drilling rigs starting in October, 2001 and the rates received for our rigs also began to fall until they stabilized in the middle of the second quarter of 2002. Natural gas and oil prices once again began to rise during the last half of 2002. As a result, the future extent of the demand for our drilling services is uncertain.

COMPETITION

All of our business' are highly competitive. Competition in onshore contract drilling traditionally involves such factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our competitors in the onshore contract drilling business are substantially larger than we are and have appreciably greater financial and other resources. The competitive environment within which we operate is uncertain and extremely price oriented.

Our oil and natural gas operations likewise encounter strong competition from major oil companies, independent operators and others. Many of these competitors have appreciably greater financial, technical and other resources and have more experience in the exploration for and production of oil and natural gas than we have.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of five oil and gas limited partnerships and five employee oil and gas limited partnerships. We formed public partnerships in 1979, 1984, 1985 and two 1986. The employee partnerships not rolled up and formed in each year subsequent to 1999 have had an interest not exceeding 5 percent of our interest, in most of the oil and natural gas wells we drill or acquire for our own account during that particular year. The total interest the employees have in our oil and natural gas wells from participating in these partnerships does not exceed one percent. The limited partners in the employee partnerships are either employees or directors of Unit or its subsidiaries. On December 31, 2002, nine of the oldest employee oil and gas limited partnerships were rolled into one of our five remaining oil and gas limited partnerships.

Under the terms of our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions on such matters as the partnership's participation in a drilling location or a property acquisition, the partnership's expenditure of funds and the distribution of funds to partners. Because the business activities of the limited partners on the one hand and the general partner on the other hand are not the same, conflicts of interest will exist and it is not possible to entirely eliminate such conflicts. Additionally, conflicts of interest may arise when we are the operator of an oil and natural gas well and also provide contract drilling services. In such cases, these drilling operations are under contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate such conflicts.

EMPLOYEES

As of March 7, 2003, we had approximately 1,177 employees in our land contract drilling operations, 62 employees in our oil and natural gas operations and 52 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

OPERATING AND OTHER RISKS

Our drilling operations are subject to the many hazards inherent in the drilling industry, including injury or death to personnel, blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather. Our exploration and production operations are also subject to many of these similar risks. Any of these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others. Generally, our drilling contracts provide for the division of responsibilities between us and our customer, and we seek to obtain indemnification from our drilling customers for some of these risks. To the extent that we are unable to transfer these risks to our drilling customers, we seek protection through insurance. However, our insurance or our indemnification agreements, if any, may not adequately protect us against liability from all of the consequences of the hazards described above. In addition, even if we have insurance coverage, we may still have a degree of exposure based on the amount of our deductible. The occurrence of an event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could result in substantial losses to us. In addition, we may not be able to obtain insurance to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

Exploration and development operations involve numerous risks that may result in dry holes, the failure to produce oil and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing and operating wells is substantial and uncertain. Our operations may be curtailed, delayed or cancelled as a result of many things beyond our control, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or delivery crews and the delivery of equipment.

A majority of the wells in which we own an interest are operated by other parties. As a result, we have little control over the operations of such wells which can act to increase our risk. Operators of these wells may act in ways that are not in our best interests.

Our future performance depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable. In general, production from oil and natural gas properties declines as reserves deplete, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in our oil and natural gas production, revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account. However, it is possible that we may not be able to continue to replace reserves. Low prices of oil and natural gas may also limit the kinds of reserves that we can economically develop. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

GOVERNMENTAL REGULATIONS

Various state and federal regulations highly affect the production and sale of oil and natural gas. All states in which we conduct activities impose restrictions on the drilling, production, transportation and sale of oil and natural gas.

Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (the "FERC") regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. The FERC's jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which the FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. The FERC's jurisdiction over natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas will be affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines is required to divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. As a result of the various omnibus rulemaking proceedings in the late 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, the interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, the FERC expanded the impact of open access regulations to intrastate commerce.

More recently, the FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline's demonstration of lack of market control in the relevant service market. We do not know what effect the FERC's other activities will have on the access to markets, the fostering of competition and the cost of doing business.

As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counter parties. We believe these changes generally have improved the access to markets for natural gas while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from our properties.

In the past, Congress has been very active in the area of natural gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation and the promotion of competition in the natural gas industry. Thus, in addition to "first sales" deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There are other legislative proposals pending in the Federal and State legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products will be affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, the FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry. We are not able to predict with certainty what effect, if any, these relatively new federal regulations or the periodic review of the index by the FERC will have on us.

Federal, state, and local agencies have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production and related operations. Oklahoma, Texas and other states require permits for drilling operations, drilling bonds and the filing of reports concerning operations and impose other requirements relating to the exploration of oil and natural gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects its profitability. Because these rules and regulations are amended or reinterpreted frequently, we are unable to predict the future cost or impact of complying with those laws.

SAFE HARBOR STATEMENT

This report, including the information we incorporate by reference, information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by or on behalf of us, contain, or may contain, certain statements that may seem to be "forward-looking statements" within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which we expect or anticipate will or may occur in the future are forward-looking statements.

The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" and similar expressions to identify forward-looking statements.

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

- the amount and nature of our future capital expenditures;
- wells to be drilled or reworked;
- prices for oil and gas;
- demand for oil and gas;
- exploitation and exploration prospects;
- estimates of proved oil and gas reserves;
- reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and gas industry;
- business strategy;
- production of oil and gas reserves;
- expansion and growth of our business and operations; and
- drilling rig utilization and drilling rig rates.

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

- the risk factors discussed in this prospectus and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any these forward-looking statements. We disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines certain factors that in the future could cause our consolidated results for 2003 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

Commodity Prices. The prices we receive for our oil and natural gas production have a direct impact on our revenues, profitability and our cash flow as well as our ability to meet our projected financial and operational goals. The prices for natural gas and crude oil are heavily dependent on a number of factors beyond our control, including the demand for oil and/or natural gas; current weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas); and the ability of current distribution systems in the United States to effectively meet the demand for oil and/or natural gas at any given time, particularly in times of peak demand which may result due to adverse weather conditions. Oil prices are extremely sensitive to foreign influences on political, social or economic underpinnings, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of both natural gas and oil are becoming more and more influenced by trading on the commodities markets which, at times, has tended to increase the volatility associated with these prices resulting, at times, in large differences in such prices even on a month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2002 production, a $.10 per Mcf change in what we receive for our natural gas production would result in a corresponding $147,100 per month ($1,765,000 annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price would have a $36,700 per month ($440,000 annualized) change in our pre-tax operating cash flow. During 2002, substantially all of our natural gas and crude oil volumes were sold at market responsive prices.

In order to reduce our exposure to short-term fluctuations in the price of oil and natural gas, we sometimes enter into hedging or swap arrangements. Our hedging or swap arrangements apply to only a portion of our production and provide only partial price protection against declines in oil and natural gas prices. These hedging or swap arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices.

Drilling Customer Demand. Demand for our drilling services is dependent almost entirely on the needs of third parties. Based on past history, such parties' requirements are subject to a number of factors, independent of any subjective factors, that directly impact the demand for our drilling rigs. These include the availability of funds to such third parties to carry out their drilling operations during any given time period which, in turn, are often subject to downward revision based on decreases in the then current prices of oil and natural gas. Many of our customers are small to mid-size oil and natural gas companies whose drilling budgets tend to be susceptible to the influences of current price fluctuations. Other factors that affect our ability to work our drilling rigs are: the weather which, under adverse circumstances, can delay or even cause the abandonment of a project by an operator; the competition faced by us in securing the award of a drilling contract in a given area; our experience and recognition in a new market area; and the availability of labor to run our drilling rigs.

Uncertainty of Oil and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data included in this document represent only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- the effects of regulations by governmental agencies;
- future oil and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows from reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows included in this document is not necessarily the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves rely based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also are affected by the following factors:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for use in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry in general.

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if we exceed the ceiling, even if prices are depressed for only a short period of time. We may be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those consummated to date by us. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Debt and Bank Borrowing. We have experienced and expect to continue to experience substantial working capital needs due to the growth in our drilling operations and our active exploration and development programs. Historically, we have funded our working capital needs through a combination of internally generated cash flow, equity financing and borrowings under our bank loan agreement. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2002, our long-term debt outstanding, all carried under our bank loan agreement, was $30.5 million. As of December 31, 2002, we had a total loan commitment of $100 million, but we elected to limit the amount available for borrowing under our bank loan agreement to $40 million in order to reduce our financing costs.

Our level of debt, the cash flow needed to satisfy our indebtedness and the covenants governing our indebtedness could:

- limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;
- place us at a competitive disadvantage to some of our competitors that are less leveraged than us;
- make us more vulnerable during periods of low oil and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt service obligations will depend on our future performance. If the requirements of our indebtedness are not satisfied, a default would be deemed to occur and our lenders would be entitled to accelerate the payment of the outstanding indebtedness. If this occurs, we would not have sufficient funds available nor would we be able to obtain the financing required to meet our obligations.

The amount of our existing debt as well as its future debt is, to a large extent, a function of the costs associated with the projects we undertake at any given time and the cash flow we receive. Generally, our normal operating costs are those associated with the drilling of oil and natural gas wells, the acquisition of producing properties, and the costs associated with the maintenance or expansion of our drilling rig fleet. To some extent, these costs, particularly the first two items, are discretionary and we maintain a degree of control regarding the timing and/or the need to incur the same. However, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to acquire a large producing property package or the need to replace a costly rig component due to an unexpected loss, which could force us to incur increased debt above that which we had expected or forecasted. Likewise, for many of the reasons mentioned above, our cash flow may not be sufficient to cover our current cash requirements which would then require us to increase our debt either through bank borrowings or otherwise.

Item 3. *Legal Proceedings*

We are a party to various legal proceedings arising in the ordinary course of our business, none of which, in our opinion, will result in judgments which would have a material adverse effect on our financial position, operating results or cash flows.

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

No matters were submitted to our security holders during the fourth quarter of 2002.

PART II

Item 5. *Market for the Registrant's Common Equity and Related Stockholder Matters*

Our common stock trades on the New York Stock Exchange under the symbol "UNT." The following table identifies the high and low sales prices per share of our common stock for the periods indicated:

	2001		2002	
QUARTER	**High**	**Low**	**High**	**Low**
First	$ 21.3750	$ 16.3000	$ 18.6000	$ 10.2400
Second	$ 23.0000	$ 14.5000	$ 20.2500	$ 16.0100
Third	$ 15.8000	$ 7.4100	$ 19.2500	$ 13.6500
Fourth	$ 14.2400	$ 8.2900	$ 20.4400	$ 16.7100

On March 7, 2003 there were 1,857 record holders of our common stock.

We have never paid cash dividends on our common stock and currently intend to continue our policy of retaining earnings from our operations. Our loan agreement prohibits us from declaring and paying dividends (other than stock dividends) in any fiscal year in an amount greater than 25 percent of our preceding year’s consolidated net income and then only if our working capital provided from operations for the previous year was equal to or greater than 175 percent of the current maturities of our long-term debt at the end of the previous year.

Item 6. *Selected Financial Data*

	Year Ended December 31,				
	1998 (1)	1999 (1)	2000	2001	2002
	(In thousands except per share amounts)				
Revenues	$ 97,274	$ 102,352	$ 201,264	$ 259,179	$ 187,636
Net Income	$ 1,428	$ 3,048	$ 34,344	$ 62,766	$ 18,244
Earnings Per Common Share:					
Basic	$ 0.05	$ 0.10	$ 0.96	$ 1.75	$ 0.47
Diluted	$ 0.05	$ 0.10	$ 0.95	$ 1.73	$ 0.47
Total Assets	$ 233,096	$ 295,567	$ 346,288	$ 417,253	$ 578,163
Long-Term Debt	$ 75,048	$ 67,239	$ 54,000	$ 31,000	$ 30,500
Other Long-Term Liabilities	$ 2,368	$ 2,325	$ 3,597	$ 4,110	$ 5,439
Cash Dividends Per Common Share	$ -	$ -	$ -	$ -	$ -

(1) Restated for the merger with Questa Oil and Gas Co.

See Management's Discussion of Financial Condition and Results of Operations for a review of 2000, 2001 and 2002 activity.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

FINANCIAL CONDITION AND LIQUIDITY

Summary. Our financial condition and liquidity depends on the cash flow from our two principal subsidiaries and borrowings under our bank loan agreement. Our cash flow is influenced mainly by the prices we receive for our natural gas production, the demand for and the dayrates we receive for our drilling rigs and, to a lesser extent, the prices we receive for our oil production. At December 31, 2002, we had cash totaling $497,000 and we had borrowed $30.5 million of the $40.0 million we have elected to have available under our loan agreement.

The following is a summary of certain financial information on December 31, 2002 and for the year ended December 31, 2002:

Working Capital	$ 16,867,000
Net Income.	$ 18,244,000
Net Cash Provided by Operating Activities. . . .	$ 70,547,000
Long-Term Debt.	$ 30,500,000
Shareholders' Equity.	$ 421,372,000
Ratio of Long-Term Debt to Total Capitalization. . . .	7%

The following table summarizes certain operating information for the years ended December 31, 2001 and 2002:

	2001	2002	Percent Change
Oil Production (Bbls) . . .	492,000	473,000	(4%)
Natural Gas Production (Mcf)	18,864,000	18,968,000	1%
Average Oil Price Received.	$ 23.62	$ 21.54	(9%)
Average Natural Gas Price Received.	$ 4.00	$ 2.87	(28%)
Average Number of Our Drilling Rigs in Use During the Period	46.3	39.1	(16%)

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. At December 31, 2002, we had borrowed $30.5 million through the bank loan.

Each year, on April 1 and October 1, our banks re-determine 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 $32.4 million on February 19, 2003.

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

The interest rate on our bank debt was 2.47 percent at December 31, 2002 and February 19, 2003. At our election, any portion of our outstanding bank debt may be fixed at the Libor Rate, as adjusted depending on the level of our debt as a percentage of the amount available for us to borrow. The Libor Rate may be fixed for periods of up to 30, 60, 90 or 180 days with the balance of our bank debt being subject to the Prime Rate. During any Libor Rate funding period, we may not pay any part of the outstanding principal balance which is subject to the Libor Rate. Borrowings subject to the Libor Rate were $30.5 million at December 31, 2002 and $31.0 million at February 19, 2003.

The loan agreement also requires us to maintain:

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

We are restricted from paying dividends (other than stock dividends) during any fiscal year in excess of 25 percent of our consolidated net income from the preceding fiscal year. Additionally, we can pay dividends if our working capital provided from our operations during the preceding year is equal to or greater than 175 percent of current maturities of long-term debt at the end of the preceding year. We also cannot incur additional debt except in certain limited exceptions. 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 third quarter of 2001, we entered into two natural gas collar contracts for approximately 38 percent of our September thru November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling of $3.68 and the other contract had a ceiling of $4.25. During the year of 2001, the collar contracts increased natural gas revenues by $2,030,000.

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 had a floor of $3.00 and a ceiling of $3.98. During the year of 2002, our natural gas hedging transactions increased natural gas revenues by $40,300. We did not have any hedging transactions outstanding at December 31, 2002.

During the first quarter of 2003, we entered into two collar contracts covering approximately 40 percent of our natural gas production for the periods of April 1, 2003 thru September 30, 2003. One collar has a floor of $4.00 and a ceiling of $5.75 and the other collar has a floor of $4.50 and a ceiling of $6.02. We also entered into two collar contracts covering approximately 25 percent of our oil production for the periods of May 1, 2003 thru December 31, 2003. One collar has a floor of $25.00 and a ceiling of $32.20 and the other collar has a floor of $26.00 and a ceiling of $31.40.

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

Impact of Prices for Our Oil and Natural Gas. Natural gas comprises 91 percent of our total oil and natural gas reserves. Any significant change in natural gas prices has a material affect on our revenues, cash flow and the value of our oil and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our production in 2002, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $147,100 per month ($1,765,000 annualized) change in our pre-tax operating cash flow. Our 2002 average natural gas price was $2.87 compared to an average natural gas price of $4.00 received 2001. A $1.00 per barrel change in our oil price would have a $36,700 per month ($440,000 annualized) change in our pre-tax operating cash flow. Our 2002 average oil price was $21.54 compared with an average oil price of $23.62 received in 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 in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our bank 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 continue to evaluate the information available to us about these buyers in an effort to reduce any possible future adverse impact to us.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when to incur such costs. We drilled 96 wells (51.87 net wells) in 2002 compared to 125 wells (53.44 net wells) in 2001. In December 2002, we acquired 73 producing oil and natural gas wells for $12.5 million. Our total capital expenditures for oil and natural gas exploration and acquisitions in 2002 totaled $58.8 million. Based on current prices, we plan to drill an estimated 140 to 150 wells in 2002 and total capital expenditures for oil and natural gas exploration and acquisitions is planned to be around $65 million.

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

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices influence the demand for our drilling rigs and the prices we can charge for our contract drilling services. Low oil and natural gas prices, during most of the 1980’s and 1990’s, reduced demand for domestic land contract drilling rigs. In the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a big increase in demand for our rigs. Demand continued to increase until the end of the third quarter of 2001 and reached a high when 52 of our rigs were working in July 2001. Because of declining natural gas prices throughout 2001, demand for our rigs dropped significantly in the fourth quarter of 2001 and stabilized with between 30 and 35 rigs operating in the first half on 2002. Natural gas and oil prices once again began to rise during the last half of 2002. With the August acquisition of 20 rigs described below, the average use of our rigs in 2002 was 39.1 rigs (63 percent) compared with 46.3 rigs (90 percent) for 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 2002 was $7,716 compared to $10,044 for 2001. Based on the average utilization of our rigs in 2002, a $100 per day change in dayrates has a $3,900 per day ($1,424,000 annualized) change in our pre-tax operating cash flow.

Utilization and dayrates for our drilling rigs will depend mainly on the price of natural gas.

Our contract drilling subsidiary provides drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties. Per regulations provided by the Securities and Exchange Commission, the profit received by our contract drilling segment of $2,259,000 and $841,000 during 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.

Drilling Acquisitions and Capital Expenditures. On August 15, 2002, we completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company, which included twenty drilling rigs, spare drilling equipment and vehicles, for 7.22 million shares of our common stock and $4.5 million in cash. Total consideration for the acquisition was valued at $127 million of which $7.7 million went to goodwill and $2.2 million went to deferred tax assets. 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. 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. The addition of these twenty rigs brought our fleet to 75. For our contract drilling operations during 2002, we incurred $139.3 million in capital expenditures, which included $7.7 million for goodwill and $2.2 million for deferred tax assets. For the year 2003, we anticipate capital expenditures of approximately $25 million for our contract drilling operations.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. As of December 31, 2002, we rolled up nine of our employee partnerships into a consolidated partnership. After the rollup, we are the general partner for ten oil and natural gas partnerships which were formed privately and publicly. The partnership's revenues and costs are shared under formulas prescribed in each limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by management to be reasonable. During 2000, 2001 and 2002, the total paid to us for all of these fees was $966,000, $1,107,000 and $929,000, respectively. We expect the fees to be about the same in 2003. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

We own a 40 percent equity interest in a natural gas gathering and processing company. Our investment, including our share of the equity in the earnings of this company, totaled $1.8 million at December 31, 2002 and is reported in other assets in our accompanying balance sheet. From time to time we may guarantee the debt of this company. However, as of December 31, 2002 and February 19, 2003, we were not guaranteeing any of the debt of this company.

Outlook. Both of our operating segments are extremely dependent on natural gas prices. These prices affect not only our production revenues, but also the future demand and rates for our contract drilling services. On February 19, 2003, the Nymex Henry Hub average contract settle price for the next twelve months was $5.59. We anticipate that if natural gas prices continue at that level, there will be an increase in demand for our rigs and an upward movement on the rates we receive for our contract drilling services. There is a certain degree of uncertainty as to whether these prices can be sustained. This uncertainty has, in turn, made it difficult to measure the future use of our drilling rigs. We would anticipate that if current natural gas prices are, in fact, maintained we will experience an upward movement in demand for our rigs.

Contractual Commitments. We have the following contractual obligations at December 31, 2002:

Contractual Obligations	Payments Due by Period: Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank Debt(1)	$ 30,500	$ -	$ 5,931	$ 20,333	$ 4,236
Hickman Note(2)	1,000	1,000	-	-	-
Retirement Agreement(3)	1,412	170	600	600	42
Operating Leases(4)	1,666	663	839	164	-
Total Contractual Obligations	$ 34,578	$1,833	$ 7,370	$ 21,097	$ 4,278

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

(2) On November 20, 1997, we acquired Hickman Drilling Company pursuant to an agreement and plan of merger entered into by and between us, Hickman Drilling Company and all of the holders of the outstanding capital stock of Hickman Drilling Company. As part of this acquisition, the former shareholders of Hickman held, as of December 31, 2002, promissory notes in the aggregate outstanding principal amount of $1.0 million (See Note 4 of our Consolidated Financial Statements). These notes were paid in full in January 2003. The notes bore interest at the Chase Prime Rate, which at December 31, 2002 was 4.25 percent.

(3) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, will be paid in monthly payments of $25,000 starting in July 2003 and continuing through June 2009 (See Note 4 of our Consolidated Financial Statements).

(4) We lease office space in Tulsa, Houston and Woodward under the terms of operating leases expiring through January 31, 2007 (See Note 9 of our Consolidated Financial Statements).

At December 31, 2002, we also have the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Amount Committed Or Accrued	Amount of Commitment Expiration Per Period: Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred Compensation Agreement(1)	$ 1,391	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,081	$ 295	Unknown	Unknown	Unknown
Gas Balancing Liability(3)	$ 1,020	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations(4)	Unknown	Unknown	Unknown	Unknown	Unknown

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheet, at the time of deferral (See Note 6 of our Consolidated Financial Statements).

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan (See Note 6 of our Consolidated Financial Statements).

(3) In December 2002, we recorded a liability on certain properties where we believe there is insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes.

(4) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2003, with a subsidiary of ours serving as General Partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of each year. These partnership agreements require, upon the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20 percent of the units outstanding. We made repurchases of $14,000 and $1,000 in 2000 and 2002, respectively, for such limited partners' interests. No repurchases were made in 2001 (See Note 9 of our Consolidated Financial Statements).

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 not included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are subject to a write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts 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 on December 31, 2002 ($4.42

per Mcf for natural gas and $29.70 per barrel for oil), the unamortized cost of our domestic oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas prices remain erratic and any significant declines below quarter-end prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

The value of our oil and natural gas reserves is used to determine the loan value under our bank 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.

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

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

We recognize revenues generated for “daywork” drilling contracts as the services are performed, which is similar to the percentage of completion method. 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, however, any profit is recorded only at the time the well is finished. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

EFFECTS OF INFLATION

In the 18 years prior to the last half of 1999, the effects of inflation on our operations was minimal due to low inflation rates and moderate demand for contract drilling services. However, starting in the last half of 1999 and throughout 2000 and the first three quarters of 2001, as drilling rig dayrates and utilization increased, the impact of inflation increased as the availability of used equipment and third party services decreased. Due to industry-wide demand for qualified labor, contract drilling labor costs increased substantially in the summer of 2000 and once again in the summer of 2001 and when rig dayrates declined in 2002 the labor rates did not come back down to the levels incurred prior to the increases. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates and the prices we receive for our oil and natural gas. If industry activity recovers and returns to levels achieved in early 2001, shortages in support equipment such as drill pipe, third party services and qualified labor could occur resulting in additional corresponding increases in our material and labor costs. These conditions may limit our ability to realize improvements in operating profits.

NEW ACCOUNTING PRONOUNCEMENTS

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). In the first quarter of 2003, the effect of the implementation of FAS 143 (unaudited) is expected to increase liabilities including deferred taxes by $11.7 million, increase the net book value of our oil and natural gas properties by $13.0 million and we anticipate adjustment to increase net income for the accumulated effect of a change in accounting principle of $1.3 million.

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. This statement eliminates an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. We do not expect the adoption of FAS 145 to have a material effect on our financial position, results of operations or cashflows.

In July 2002, the FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Cost Associated with Exit or Disposal Activities" ("FAS 146"). FAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. FAS 146 nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an

Activity (including Certain Costs Incurred in a Restructuring)." We do not expect the adoption of FAS 146 to have a material effect on our financial position, results of operations or cashflow.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FAS 123" ("FAS 148"). FAS 148 provides additional transition guidance for companies that elect to voluntarily adopt the accounting provisions of FAS 123, "Accounting For Stock-Based Compensation." FAS 148 does not change the provisions of FAS 123 that permit entities to continue to apply the intrinsic value method of APB 25, "Accounting for Stock Issued to Employees" ("APB 25"). Since we apply APB 25, our accounting for stock-based compensation will not change as a result of FAS 148. FAS 148 does require certain new disclosures in both annual and interim financial statements. The required annual disclosures were effective immediately for us and have been included in Note 1 of our financial statements. The new interim disclosure provisions will be effective for us in the first quarter of 2003.

On November 25, 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, an interpretation of FASB Statements No. 5, 57, and 107 and Rescission of FASB Interpretation No. 34" ("FIN 45"). FIN 45 clarifies the requirements of FASB Statement No. 5, Accounting for Contingencies (FAS 5), relating to the guarantor's accounting for, and disclosure of, the issuance of certain types of guarantees. For guarantees that fall within the scope of FIN 45, the Interpretation requires that guarantors recognize a liability equal to the fair value of the guarantee upon its issuance. The Interpretation's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of the Interpretation. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. We have guaranteed liabilities in the past which would fall under the terms of FIN 45, but we do not have any such guarantees at December 31, 2002.

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

RESULTS OF OPERATIONS

2002 versus 2001

Provided below is a comparison of selected operating and financial data for the year of 2002 versus the year of 2001:

	2001	2002	Percent Change
Total Revenue	$ 259,179,000	$ 187,636,000	(28%)
Net Income	$ 62,766,000	$ 18,244,000	(71%)
Oil and Natural Gas:			
Revenue	$ 90,237,000	$ 67,959,000	(25%)
Average natural gas price (Mcf)	$ 4.00	$ 2.87	(28%)
Average oil price (Bbl)	$ 23.62	$ 21.54	(9%)
Natural gas production (Mcf)	18,864,000	18,968,000	1%
Oil production (Bbl)	492,000	473,000	(4%)
Operating profit (revenue less operating costs)	$ 68,041,000	$ 47,164,000	(31%)
Operating margin	75%	69%	
Depreciation, depletion and amortization rate (Mcfe)	$ 0.91	$ 1.04	14%
Depreciation, depletion and amortization (includes $2,083,000 and $346,000 write off of interest in Shenandoah in 2001 and 2002)	$ 22,116,000	$ 23,338,000	6%
Drilling:			
Revenue	$ 167,042,000	$ 118,173,000	(29%)
Percentage of revenue from daywork contracts	99%	91%	
Average number of rigs in use	46.3	39.1	(16%)
Average dayrate on daywork contracts	$ 10,044	$ 7,716	(23%)
Operating profit (revenue less operating costs)	$ 76,036,000	$ 26,835,000	(65%)
Operating margin	46%	23%	
Depreciation	$ 13,888,000	$ 14,684,000	6%
General and Administrative Expense	$ 8,476,000	$ 8,712,000	3%
Interest Expense	$ 2,818,000	$ 973,000	(65%)
Average Interest Rate	5.7%	3.0%	(47%)

Average Long-Term Debt Outstanding	$ 44,995,000	$ 24,771,000	(45%)

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 during 2002 compared to 2001. Production in equivalent Mcf was almost the same in 2002 as in 2001. Total operating cost decreased due to lower gross production taxes resulting from lower revenues. Total depreciation, depletion and amortization ("DD&A") on our oil and natural gas properties increased due to the increase in the DD&A rate in 2002, which resulted from higher development drilling cost per equivalent Mcf. The increase would have been larger, but included in 2001 DD&A was the write down of our investment in Shenandoah Resources LTD. of $2.1 million. The remaining balance of our investment in Shenandoah Resources LTD. of $346,000 was written off in the third quarter of 2002.

Reduced natural gas prices, especially in the fourth quarter of 2001 and the first quarter of 2002, 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 declined between 2002 and 2001. Approximately 9 percent of our total drilling revenues in 2002 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. One percent of our total drilling revenues came from footage and turnkey contracts in 2001. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002. The increase was partially offset by lower rig use.

General and administrative expense was higher in 2002 due to increases in labor cost, insurance expense and outside contract services. In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense plus accrued interest will be paid in $25,000 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.

2001 versus 2000

Provided below is a comparison of selected operating and financial data for the year of 2001 versus the year of 2000:

	2000	2001	Percent Change
Total Revenue	$ 201,264,000	$ 259,179,000	29%
Net Income	$ 34,344,000	$ 62,766,000	83%
Oil and Natural Gas:			
Revenue	$ 92,016,000	$ 90,237,000	(2%)
Average natural gas price (Mcf)	$ 3.91	$ 4.00	2%
Average oil price (Bbl)	$ 26.95	$ 23.62	(12%)
Natural gas production (Mcf)	19,285,000	18,864,000	(2%)
Oil production (Bbl)	488,000	492,000	1%
Operating profit (revenue less operating costs)	$ 72,262,000	$ 68,041,000	(6%)
Operating margin	79%	75%	
Depreciation, depletion and amortization rate (Mcfe)	$ 0.82	$ 0.91	11%
Depreciation, depletion and amortization (includes $2,083,000 write off of interest in Shenandoah in 2001)	$ 18,492,000	$ 22,116,000	20%
Drilling:			
Revenue	$ 108,075,000	$ 167,042,000	55%
Percentage of revenue from daywork contracts	85%	99%	
Average number of rigs in use	39.8	46.3	16%
Average dayrate on daywork contracts	$ 6,957	$ 10,044	44%
Operating profit (revenue less operating costs)	$ 24,024,000	$ 76,036,000	217%
Operating margin	22%	46%	
Depreciation	$ 11,999,000	$ 13,888,000	16%
General and Administrative Expense	$ 6,560,000	$ 8,476,000	29%
Interest Expense	$ 5,136,000	$ 2,818,000	(45%)
Average Interest Rate	7.9%	5.7%	(28%)
Average Long-Term Debt Outstanding	$ 62,302,000	$ 44,995,000	(28%)

Total revenues and net income were higher in 2001 versus 2000 due to increases in the use of our drilling rigs, as well as, the dayrates we received for the use of the drilling rigs.

Oil and natural gas revenues, operating profits and operating profit margins were all negatively affected by lower natural gas production and drops in the oil price we received between 2001 and 2000. Total operating cost increased due to the addition of new wells through development drilling and increases in ad valorem taxes, workover expenses and compression fees. Operating margins also decreased due to declines in production on older wells without corresponding declines in operating expenses. Depreciation, depletion and amortization ("DD&A") increased in 2001 due to a write down of our investment in Shenandoah Resources LTD. by $2.1 million and an increase in our DD&A rate per equivalent Mcf resulting from higher development drilling cost per equivalent Mcf.

Higher natural gas prices in the last quarter of 2000 and the first quarter of 2001 increased the demand for our drilling rigs which in turn pushed contract drilling dayrates higher. As a result, drilling revenues and operating margins increased between 2001 and 2000. Our contract drilling operating cost per rig per day decreased $400 in 2001 when compared with 2000 as increased usage reduced the impact of our fixed indirect drilling expenses. Total contract drilling operating costs were up primarily due to increased utilization and increases in field labor cost.

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

Item 7a. Quantitative and Qualitative Disclosures about Market Risk

Our operations are exposed to market risks primarily as a result of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. The price we receive is primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, prices we received for our oil and natural gas production fluctuated and such fluctuation is expected to continue. The price of natural gas also effects the demand for our rigs and the amount we can charge for the use of the rigs. Based on our 2002 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $147,100 per month ($1,765,000 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $36,700 per month ($440,000 annualized) change in our pre-tax operating cash flow.

In an effort to try and reduce the impact of price fluctuations, over the past several years we periodically have used hedging strategies to hedge the price we will receive for a portion of our future oil and natural gas production. A detailed explanation of those transactions has been included under hedging in the financial condition portion of management's discussion and analysis of financial condition and results of operations included above.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the prime rate or the London Interbank Offered Rate ("Libor Rate"). At our election, borrowings under our revolving credit and term loan may be fixed at the Libor Rate for periods up to 180 days. Historically, we have not utilized any financial instruments, such as interest rate swaps, to manage our exposure to increases in interest rates. However, we may use such financial instruments in the future should our assessment of future interest rates warrant such use. Based on our average outstanding long-term debt in 2002, a one percent change in the floating rate would change our annual pre-tax cash flow by approximately $248,000.

Item 8. *Financial Statements and Supplementary Data*

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2001	2002
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 391	$ 497
Accounts receivable (less allowance for doubtful accounts of $604 and $1,203)	33,886	33,912
Materials and supplies	5,358	8,794
Income tax receivable	3,198	3,602
Prepaid expenses and other	3,761	4,594
Total current assets	46,594	51,399
Property and Equipment:		
Drilling equipment	244,698	369,777
Oil and natural gas properties, on the full cost method	406,491	465,250
Transportation equipment	6,441	6,856
Other	9,231	9,906
	666,861	851,789
Less accumulated depreciation, depletion, amortization and impairment	304,643	341,031
Net property and equipment	362,218	510,758
Other Assets	8,441	16,006
Total Assets	$ 417,253	$ 578,163

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

	As of December 31, 2001	As of December 31, 2002
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and other liabilities	$ 1,893	$ 1,465
Accounts payable	16,292	21,119
Accrued liabilities	10,616	11,921
Contract advances	240	27
Total current liabilities	29,041	34,532
Long-Term Debt	31,000	30,500
Other Long-Term Liabilities (Note 4)	4,110	5,439
Deferred Income Taxes	73,940	86,320
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, 75,000,000 shares authorized, 36,006,267 and 43,339,400 shares issued, respectively	7,201	8,668
Capital in excess of par value	141,977	264,180
Retained earnings	130,280	148,524
Treasury stock at cost (30,000 shares)	(296)	-
Total shareholders' equity	279,162	421,372
Total Liabilities and Shareholders' Equity	$ 417,253	$ 578,163

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2000	2001	2002
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 108,075	$ 167,042	$ 118,173
Oil and natural gas	92,016	90,237	67,959
Other	1,173	1,900	1,504
Total revenues	201,264	259,179	187,636
Expenses:			
Contract drilling:			
Operating costs	84,051	91,006	91,338
Depreciation	11,999	13,888	14,684
Oil and natural gas:			
Operating costs	19,754	22,196	20,795
Depreciation, depletion, amortization and impairment	18,492	22,116	23,338
General and administrative	6,560	8,476	8,712
Interest	5,136	2,818	973
Total expenses	145,992	160,500	159,840
Income Before Income Taxes	55,272	98,679	27,796
Income Tax Expense:			
Current	621	5,609	(3,469)
Deferred	20,307	30,304	13,021
Total income taxes	20,928	35,913	9,552
Net Income	$ 34,344	$ 62,766	$ 18,244
Net Income Per Common Share:			
Basic	$ 0.96	$ 1.75	$ 0.47
Diluted	$ 0.95	$ 1.73	$ 0.47

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, 2000, 2001 and 2002

	Common Stock	Capital In Excess Of Par Value	Retained Earnings	Accumulated Other Comprehen-Sive Income	Treasury Stock	Total
			(In thousands)			
Balances, January 1, 2000	$ 7,128	$ 139,207	$ 33,170	$ -	$ -	$ 179,505
Net income	-	-	34,344	-	-	34,344
Activity in employee compensation plans (135,419 shares)	26	665	-	-	-	691
Balances, December 31, 2000	7,154	139,872	67,514	-	-	214,540
Net Income	-	-	62,766	-	-	62,766
Activity in employee compensation plans (237,923 shares)	47	2,105	-	-	-	2,152
Purchase of treasury shares (30,000 shares)	-	-	-	-	(296)	(296
Other comprehensive income (net of tax):						
Change in value of cash flow derivative instruments used as cash flow hedges	-	-	-	1,258	-	1,258
Adjustment reclasifica-tion - derivative settlements	-	-	-	(1,258)	-	(1,258
Balances, December 31, 2001	$ 7,201	$ 141,977	$130,280	$ -	$ (296)	$ 279,162

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY - CONTINUED
Year Ended December 31, 2000, 2001 and 2002

	Common Stock	Capital In Excess Of Par Value	Retained Earnings	Accumulated Other Comprehen-Sive Income	Treasury Stock	Total
			(In thousands)			
Balances, December 31, 2001	$ 7,201	$ 141,977	$130,280	$ -	$ (296)	$ 279,16
Net Income	-	-	18,244	-	-	18,24
Activity in employee compensation plans (113,133 shares)	23	1,156	-	-	296	1,47
Issuance of stock for acquisistion (7,220,000 shares)	1,444	121,047	-	-	-	122,49
Other comprehensive income (net of tax):						
Change in value of cash flow derivative instruments used as cash flow hedges	-	-	-	25	-	2
Adjustment reclasifica-tion - derivative settlements	-	-	-	(25)	-	(2
Balances, December 31, 2002	$ 8,668	$ 264,180	$148,524	$ -	$ -	$ 421,37

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,		
	2000	2001	2002
	(In thousands)		
Cash Flows From Operating Activities:			
Net Income	$ 34,344	$ 62,766	$ 18,244
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization and impairment	30,946	36,642	38,657
Equity in net earnings of unconsolidated investments	-	(1,148)	(745)
Loss (gain) on disposition of assets	(969)	(56)	(69)
Employee compensation plans	443	2,873	1,165
Bad debt expense	350	-	603
Deferred tax expense	20,307	30,304	13,021
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(18,500)	6,334	(43)
Materials and supplies	(543)	(1,556)	(3,436)
Prepaid expenses and other	(96)	(3,533)	2,365
Accounts payable	(1,370)	(155)	1,784
Accrued liabilities	3,067	929	(350)
Contract advances	(179)	61	(213)
Other liabilities	(440)	(440)	(436)
Net cash provided by operating activities	67,360	133,021	70,547

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,		
	2000	2001	2002
		(In thousands)	
Cash Flows From Investing Activities:			
Capital expenditures (including producing property acquisitions)	$ (60,447)	$(108,339)	$ (75,225)
Proceeds from disposition of property and equipment	4,259	2,631	1,949
(Acquisition) disposition of other assets	(2,656)	17	540
Net cash used in investing activities	(58,844)	(105,691)	(72,736)
Cash Flows From Financing Activities:			
Borrowings under line of credit	31,200	57,200	36,700
Payments under line of credit	(44,439)	(79,200)	(36,200)
Net payments on notes payable and other long-term debt	(556)	(1,000)	(1,161)
Proceeds from exercise of Stock options	250	609	413
Book overdrafts (Note 1)	3,108	(4,978)	2,543
Acquisition of treasury stock	-	(296)	-
Net cash provided by (used in) financing activities	(10,437)	(27,665)	2,295
Net Increase (Decrease) in Cash and Cash Equivalents	(1,921)	(335)	106
Cash and Cash Equivalents, Beginning of Year	2,647	726	391
Cash and Cash Equivalents, End of Year	$ 726	$ 391	$ 497
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Interest	$ 5,135	$ 2,807	$ 1,053
Income taxes	$ 519	$ 7,779	$ (4,585)

See Note 2 for non-cash investing activities.

The accompanying notes are an integral part of the
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 ("Unit"). The investment in limited partnerships is accounted for on the proportionate consolidation method, whereby Unit's share of the partnerships' assets, liabilities, revenues and expenses is included in the appropriate classification in the accompanying consolidated financial statements.

Nature of Business. Unit is engaged in the land contract drilling of natural gas and oil wells and the exploration, development, acquisition and production of oil and natural gas properties. Unit's current contract drilling operations are focused primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and the Rocky Mountain regions. Unit's primary exploration and production operations are also conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of its contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas. At December 31, 2002, Unit had an interest in a total of 3,304 wells and served as operator of 707 of those wells. Unit provides land contract drilling services for a wide range of customers using the drilling rigs, which it owns and operates. In 2002, 68 of Unit's 75 rigs performed contract drilling services.

Drilling Contracts. Unit recognizes revenues generated from "daywork" drilling contracts as the services are performed, which is similar to the percentage of completion method. Under "footage" and "turnkey" contracts, Unit bears the risk of completion of the well therefore, revenues and expenses are recognized using the completed contract method. The duration of all three types of contracts range typically from 20 to 90 days, but some of our daywork contracts in the Rocky Mountains can range up to one year. The entire amount of a 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" contracts, which are still in process at the end of the period, and are included in other current assets.

Cash Equivalents and Book Overdrafts. Unit includes as cash equivalents, certificates of deposits and all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued prior to the end of the period, but not presented to Unit's bank for payment prior to the end of the period. At December 31, 2001 and 2002, book overdrafts of $1.1 million and $3.6 million have been included in accounts payable.

Property and Equipment. Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and betterments are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using 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. Unit 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.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that 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 Unit to reduce the carrying value of property and equipment.

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 dispositions 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.

Goodwill. Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company and CDC Drilling Company over the fair value of the net assets acquired. Prior to January 1, 2002 goodwill was amortized on the straight-line method using a 25 year life. Unit expensed $243,000 annually for the amortization of goodwill. On July 20, 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("FAS 142"). For goodwill and intangible assets recorded in the financial statements, FAS 142 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. FAS 142 became effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). Net goodwill reported in other assets at December 31, 2001 and 2002 was $5,088,000 and $12,794,000, respectively, and is all related to the drilling segment. Goodwill of $7,009,000 is expected to be deductible for tax purposes.

Oil and Natural Gas Operations. Unit 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. Unit capitalizes internal costs that can be directly identified with its acquisition, exploration and development activities. Independent petroleum engineers annually review Unit's determination of its oil and natural gas reserves. The average composite rates used for depreciation, depletion and amortization ("DD&A") were $0.82, $0.91 and $1.04 per Mcfe in 2000, 2001 and 2002, respectively. The 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. Unit's unproved properties totaling $16.0 million are excluded from the DD&A calculation. 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. The full cost ceiling is based principally on the estimated future discounted net cash flows from Unit's oil and natural gas properties. As discussed in Note 12, such estimates are imprecise.

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 Unit has an interest or on properties in which a partnership, of which Unit is a general partner, has an interest. Accordingly, in 2000, 2001 and 2002, Unit recorded $179,000, $2,259,000 and $841,000 of contract drilling profits, respectively, as a reduction of the carrying value of its oil and natural gas properties rather than including these profits in current operations.

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in ten oil and natural gas limited partnerships sold privately and publicly. Some of Unit's officers, directors and employees own the interests in most of these partnerships. Unit shares partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The partnerships also reimburse Unit for certain administrative costs incurred on behalf of the partnerships.

Income Taxes. Measurement of current and deferred income 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. 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. Unit uses the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Unit estimates its December 31, 2002 balancing position to be approximately 1.9 Bcf on under-produced properties and approximately 2.3 Bcf on over-produced properties. Unit has recorded a receivable of $485,000 on certain wells where we estimated that insufficient reserves are available for Unit to recover the under-production from future production volumes. Unit has also recorded a liability of $1,020,000 on certain properties where we believe there is insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Unit's policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which Unit has imbalances are not material.

Equity Investments. Unit owns a 40 percent equity interest in a natural gas gathering and processing company. The investment, including Unit's share of the equity in the earnings of this company, totaled $1.8 million at December 31, 2002 and is reported in other assets.

Employee and Director Stock Based Compensation. Unit applies APB Opinion 25 in accounting for its stock option plans for its employees and directors, which are explained more fully in Note 6. Under this standard, no compensation expense is recognized for grants of options, which include an exercise price equal to or greater than the market price of the stock on the date of grant. Accordingly, based on Unit's grants in 2000, 2001 and 2002 no compensation expense has been recognized. Compensation expense included in reported net income is Unit's matching 401(k) contribution (See Note 6). Had compensation been determined on the basis of fair value pursuant to FASB Statement No. 123, net income and earnings per share would have been reduced as follows:

	2000	2001	2002
Net Income, as Reported (In Thousands)	$ 34,344	$ 62,766	$ 18,244
Add Stock Based Employee Compensation Expense Included in Reported Net Income - Net of Tax	369	671	669
Less Total Stock Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(727)	(1,615)	(1,488)
Pro Forma Net Income	$ 33,986	$ 61,822	$ 17,425
Basic Earnings per Share:			
As reported	$ 0.96	$ 1.75	$ 0.47
Pro forma	$ 0.95	$ 1.72	$ 0.45
Diluted Earnings per Share:			
As reported	$ 0.95	$ 1.73	$ 0.47
Pro forma	$ 0.94	$ 1.71	$ 0.45

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility in 2000 and 2001 was 0.55 and in 2002 was 0.53, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 5.26, 5.41 and 4.24 percent in 2000, 2001 and 2002, respectively. Expected life ranged from 1 to 10 years based on prior experience depending on the vesting periods involved and the make up of participating employees. The aggregate fair value of options granted during 2000 and 2002 under the Stock Option Plan were $1,470,000 and $1,669,000, respectively. No options were issued under the Stock Option Plan in 2001. Under the Non-Employee Directors' Stock Option Plan the aggregate fair value of options granted during 2000, 2001 and 2002 were $99,000, $201,000 and $262,000, respectively.

Self Insurance. Unit utilizes self insurance programs for employee group health and worker's compensation. Self insurance costs are accrued based upon the aggregate of estimated liabilities for reported claims and claims incurred but not yet reported. Accrued liabilities include $4,583,000 and $3,632,000 for employer group health insurance and worker's compensation at December 31, 2001 and 2002, respectively. Due to high premium cost, Unit decided to increase its deductible for general liability claims to $200,000 and to $1.0 million for rig physical damage claims.

Treasury Stock. On August 30, 2001, Unit's Board of Directors authorized the purchase of up to one million shares of Unit's common stock. The timing of stock purchases are made at the discretion of management. During 2001, 30,000 shares were repurchased for $296,000. These shares were used for a portion of the company match to the 401(k) Employee Thrift Plan. No treasury stock was owned by Unit at December 31, 2002.

Financial Instruments and Concentrations of Credit Risk. Financial instruments, which potentially subject Unit to concentrations of credit risk, consist primarily of trade receivables with a variety of national and international oil and natural gas companies. Unit 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 Unit's customer base. During 2002, one purchaser of Unit's oil and natural gas production accounted for approximately 11 percent of consolidated revenues. At December 31, 2002 accounts receivable from one oil and natural gas purchaser was approximately $713,000. In addition, at December 31, 2001 and 2002, Unit had a concentration of cash of $2.0 million and $3.0 million, respectively, with one bank.

Hedging Activities. On January 1, 2001, Unit adopted Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No.'s 137 and 138), "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). This statement requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, Unit is required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under FAS 133 must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

Unit periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists. Initial adoption of this standard was not material. In the first quarter of 2000, Unit entered into swap transactions in an effort to lock in a portion of its daily production at the higher oil prices which currently existed. These transactions applied to approximately 50 percent of Unit's daily oil production covering the period from April 1, 2000 to July 31, 2000 and 25 percent of our oil production for August and September of 2000, at prices ranging from $24.42 to $27.01.

Unit entered into a collar contract for approximately 25 percent of its daily production for the period covering November 1, 2000 to February 28, 2001. The collar had a floor of $26.00 and a ceiling of $33.00 and Unit received $0.86 per barrel for entering into the collar transaction. During 2000, the net effect of these hedging transactions yielded a reduction in Unit's oil revenues of $465,000. During the first quarter of 2001, the net effect of this hedging transaction yielded an increase in oil revenues of $17,200. During the second quarter of 2001, Unit entered into a natural gas collar contract for approximately 36 percent of its June and July 2001 natural gas production, at a floor price of $4.50 and a ceiling price of $5.95. During the third quarter of 2001, Unit entered into two natural gas collar contracts for approximately 38 percent of its September thru November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling price of $3.68 and the other contract had a ceiling price of $4.25. During 2001 natural gas collar contracts added $2,030,000 to Unit's natural gas revenues.

On April 30, 2002, Unit entered into a collar contract covering approximately 19 percent of its natural gas production for the periods of April 1, 2002 thru October 31, 2002. The collar had a floor of $3.00 and a ceiling of $3.98. During the year of 2002, the natural gas hedging transactions increased natural gas revenues by $40,300. At December 31, 2002, Unit was not holding any natural gas or oil derivative contracts.

During the first quarter of 2003, Unit entered into two collar contracts covering approximately 40 percent of its natural gas production for the periods of April 1, 2003 thru September 30, 2003. One collar has a floor of $4.00 and a ceiling of $5.75 and the other collar has a floor of $4.50 and a ceiling of $6.02. Unit also entered into two collar contracts covering approximately 25 percent of its oil production for the periods of May 1, 2003 thru December 31, 2003. One collar has a floor of $25.00 and a ceiling of $32.20 and the other collar has a floor of $26.00 and a ceiling of $31.40.

Accounting Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Impact of Financial Accounting Pronouncements.

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 Unit), 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 Unit's depleted wells) in the period in which the liabilities are incurred (at the time the wells are drilled). In the first quarter of 2003, the effect of the implementation of FAS 143 (unaudited) is expected to increase liabilities including deferred taxes by $11.7 million, increase the net book value of Unit's oil and natural gas properties by $13.0 million and the anticipated adjustment to increase net income for the accumulated effect of a change in accounting principle is expected to be $1.3 million.

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. This statement eliminates an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. Unit does not expect the adoption of FAS 145 to have a material effect on our financial position, results of operations or cashflows.

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

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FAS 123" ("FAS 148"). FAS 148 provides additional transition guidance for companies that elect to voluntarily adopt the accounting provisions of FAS 123, "Accounting For Stock-Based Compensation." FAS 148 does not change the provisions of FAS 123 that permit entities to continue to apply the intrinsic value method of APB 25, "Accounting for Stock Issued to Employees" ("APB 25"). Since Unit applies APB 25, its accounting for stock-based compensation will not change as a result of FAS 148. FAS 148 does require certain new disclosures in both annual and interim financial statements. The required annual disclosures were effective immediately for Unit and have been included above in Note 1 of the Company's financial statements. The new interim disclosure provisions will be effective for Unit in the first quarter of 2003.

On November 25, 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, an interpretation of FASB Statements No. 5, 57, and 107 and Rescission of FASB Interpretation No. 34" ("FIN 45"). FIN 45 clarifies the requirements of FASB Statement No. 5, Accounting for Contingencies ("FAS 5"), relating to the guarantor's accounting for, and disclosure of, the issuance of certain types of guarantees. For guarantees that fall within the scope of FIN 45, the Interpretation requires that guarantors recognize a liability equal to the fair value of the guarantee upon its issuance. The Interpretation's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of the Interpretation. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. Unit has guaranteed liabilities in the past which would fall under the terms of FIN 45, but it does not have any such guarantees at December 31, 2002.

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

NOTE 2 - ACQUISITIONS

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

Total consideration given in the acquisition was determined based on the depth capacity of the rigs, the working condition of the rigs and the ability of the rigs to enhance Unit's ability to provide services and equipment required by our customers on a timely basis within the Anadarko and Gulf Coast areas were the rigs are located. The calculation and allocation of the total consideration paid for the acquisition are as follows (in thousands):

Calculation of Consideration Paid:

Unit Corporation common stock	
(7,220,000 shares at $16.96556 per share)	$ 122,491
Cash	4,500
Total consideration	$ 126,991

Allocation of Total Consideration Paid:

Drilling rigs	$ 112,994
Spare drilling equipment	3,500
Vehicles	636
Deferred tax asset	2,155
Goodwill	7,706
Total consideration	$ 126,991

Unaudited summary pro forma results of operations for the Company, reflecting the above acquisitions as if they had occurred at the beginning of the year ended December 31, 2001 are as follow:

	Year Ended December 31, 2001	**Year Ended December 31, 2002**
Revenues	$ 311,104,000	$ 215,805,000
Net Income	$ 70,457,000	$ 15,320,000
Net Income per Common Share (Diluted)	$ 1.62	$ 0.34

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 - EARNINGS PER SHARE

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

	INCOME (NUMERATOR)	WEIGHTED SHARES (DENOMINATOR)	PER-SHARE AMOUNT
For the Year Ended December 31, 2000:			
Basic earnings per common share	$ 34,344,000	35,723,000	$ 0.96
Effect of dilutive stock options		409,000	
Diluted earnings per common share	$ 34,344,000	36,132,000	$ 0.95
For the Year Ended December 31, 2001:			
Basic earnings per common share	$ 62,766,000	35,967,000	$ 1.75
Effect of dilutive stock options		291,000	
Diluted earnings per common share	$ 62,766,000	36,258,000	$ 1.73
For the Year Ended December 31, 2002:			
Basic earnings per common share	$ 18,244,000	38,844,000	$ 0.47
Effect of dilutive stock options		268,000	
Diluted earnings per common share	$ 18,244,000	39,112,000	$ 0.47

The following options and their average exercise prices were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of common shares for the years ended December 31,:

	2000	**2001**	**2002**
Options	144,000	153,000	198,500
Average Exercise Price	$ 16.59	$ 16.79	$ 19.01

NOTE 4 - LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-term debt consisted of the following as of December 31, 2001 and 2002:

	2001	**2002**
	(In thousands)	
Revolving Credit and Term Loan, with Interest at December 31, 2001 and 2002 of 3.3 Percent and 2.5 Percent, Respectively	$ 30,000	$ 30,500
Notes Payable for Hickman Drilling Company Acquisition with Interest at December 31, 2001 and 2002 of 4.75 Percent and 4.25 Percent, Respectively	2,000	1,000
	32,000	31,500
Less Current Portion	1,000	1,000
Total Long-Term Debt	$ 31,000	$ 30,500

At December 31, 2002, Unit has a $100 million bank loan agreement consisting of a revolving credit facility through May 1, 2005 and a term loan thereafter, maturing on May 1, 2008. Borrowings under the loan agreement are limited to a commitment amount. Although, the current value of Unit's assets under the latest loan value computation supported a full $100 million, Unit elected to set the loan commitment at $40 million in order to reduce costs. The loan value under the revolving credit facility is subject to a semi-annual re-determination calculated primarily as the sum of a percentage of the discounted future value of Unit's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of Unit’s drilling rig fleet, limited to $20 million, is added to the loan value. Any declines in commodity prices would adversely impact the determination of the loan value.

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. Subsequent to 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.

At Unit’s election, any portion of the debt outstanding may be fixed at the Libor Rate for 30, 60, 90 or 180 days. During any Libor Rate funding period the outstanding principal balance of the note to which such Libor Rate option applies may not be paid. Borrowings under the Prime Rate option may be paid anytime in part or in whole without premium or penalty.

Unit pays an origination fee equal to one percent of the elected loan commitment annually and a facility fee of 3/8 of one percent is charged for any unused portion of the commitment amount. Some of Unit’s drilling rigs are collateral for such indebtedness and the balance of Unit’s assets are subject to a negative pledge.

The loan 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 Unit during the preceding fiscal year, and only if working capital provided from operations during said year is equal to or greater than 175 percent of current maturities of long-term debt at the end of such year, (ii) the incurrence by Unit 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 Unit or any of its subsidiaries, except in favor of its banks. The loan agreement also requires that Unit 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 and a ratio of total liabilities, as defined in the loan agreement, to consolidated tangible net worth not greater than 1.65 to 1. In addition, working capital provided by operations, as defined in the loan agreement, cannot be less than $40 million in any year.

In November 1997, Unit completed the acquisition of Hickman Drilling Company. In association with this acquisition, we issued an aggregate of $5.0 million in promissory notes payable in five equal annual installments commencing January 2, 1999, with interest at the Prime Rate. At December 31, 2002, $1 million remained outstanding on these promissory notes and they were paid in full in January 2003.

Other long-term liabilities consisted of the following as of December 31, 2001 and 2002:

	2001	2002
	(In thousands)	
Separation Benefit Plan	$ 1,959	$ 2,081
Deferred Compensation Plan	1,277	1,391
Retirement Agreement	1,330	1,412
Gas Balancing Liability	-	1,020
Natural Gas Purchaser Prepayment	437	-
	5,003	5,904
Less Current Portion	893	465
Total Other Long-Term Liabilities	$ 4,110	$ 5,439

Estimated annual principal payments under the terms of long-term debt and other long-term liabilities from 2003 through 2007 are $1,465,000, $300,000, $6,231,000, $10,467,000 and $10,467,000. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2002 approximates its fair value.

NOTE 5 - INCOME TAXES

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

	2000	2001	2002
		(In thousands)	
Income Tax Expense Computed by Applying the Statutory Rate	$ 19,345	$ 34,538	$ 9,739
State Income Tax, Net of Federal Benefit	1,575	2,859	834
Statutory Depletion and Other	8	(1,484)	(1,021)
Income tax expense	$ 20,928	$ 35,913	$ 9,552

Deferred tax assets and liabilities are comprised of the following at December 31, 2001 and 2002:

	2001	2002
	(In thousands)	
Deferred Tax Assets:		
Allowance for losses and nondeductible accruals	$ 3,867	$ 3,942
Net operating loss carryforward	-	17,752
Statutory depletion carryforward	2,874	4,231
Alternative minimum tax credit carryforward	5,196	395
Gross deferred tax assets	11,937	26,320
Deferred Tax Liability:		
Depreciation, depletion and amortization	(83,720)	(110,598)
Net deferred tax liability	(71,783)	(84,278)
Current Deferred Tax Asset	2,157	2,042
Non-Current - Deferred Tax Liability	$ (73,940)	$ (86,320)

Realization of the deferred tax asset is dependent on generating sufficient future taxable income. Although realization is not assured, management believes it is more likely than not that the deferred tax asset will be realized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near-term if estimates of future taxable income are reduced.

At December 31, 2002, Unit has an excess statutory depletion carryforward of approximately $11,135,000, which may be carried forward indefinitely and is available to reduce future taxable income, subject to statutory limitations. At December 31, 2002, Unit has net operating loss carryforwards of approximately $46,700,000 which expire from 2019 to 2022.

NOTE 6 - EMPLOYEE BENEFIT AND COMPENSATION PLANS
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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. On May 3, 1995, Unit's shareholders approved and amended the Plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued 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. No shares were issued under the Plan in 2000, 2001 and 2002.

Unit also has a Stock Option Plan (the "Option Plan"), which provides for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The Option Plan permits the issuance of qualified or nonqualified stock options. Options granted typically become exercisable at the rate of 20 percent per year one year after being granted and expire after ten years from the original grant date. The exercise price for options granted under this plan is the fair market value of the common stock on the date of the grant.

Activity pertaining to the Stock Option Plan is as follows:

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at January 1, 2000	657,600	$ 4.41
Granted	146,000	16.59
Exercised	(79,700)	4.19
Cancelled	(4,200)	4.94
Outstanding at December 31, 2000	719,700	6.87
Exercised	(177,200)	3.13
Cancelled	(10,400)	10.26
Outstanding at December 31, 2001	532,100	8.09
Granted	160,000	19.03
Exercised	(59,400)	5.67
Outstanding at December 31, 2002	632,700	$ 11.08

	OUTSTANDING OPTIONS AT DECEMBER 31, 2002		
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.75 - $ 4.00	236,500	4.3 years	$ 3.42
$ 7.25 - $10.00	94,200	4.1 years	$ 8.58
$11.31 - $14.06	6,500	7.3 years	$ 13.61
$16.69 - $19.04	295,500	9.0 years	$ 17.95

	EXERCISABLE OPTIONS AT DECEMBER 31, 2002	
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.75 - $ 4.00	196,000	$ 3.36
$ 7.25 - $10.00	91,700	$ 8.61
$11.31 - $14.06	3,200	$ 13.18
$16.69 - $19.04	64,200	$ 17.05

Options for 407,900, 329,300 and 355,100 shares were exercisable with weighted average exercise prices of $4.24, $6.25 and $7.28 at December 31, 2000, 2001 and 2002, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the “Old Plan”) and in February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors’ Stock Option Plan (the "Directors' Plan"). Under the Directors’ Plan, which replaced the Old Plan, an aggregate of 300,000 shares of Unit’s common stock may be issued upon exercise of the stock options. Under the Old Plan, on the first business day following each annual meeting of stockholders of Unit, each person who was then a member of the Board of Directors of Unit and who was not then an employee of Unit or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. Under the Directors’ Plan, commencing with the year 2000 annual meeting, the amount granted has been increased to 3,500 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	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at January 1, 2000	77,500	$ 5.86
Granted	17,500	12.19
Outstanding at December 31, 2000	95,000	7.03
Granted	17,500	17.54
Exercised	(37,000)	6.80
Outstanding at December 31, 2001	75,500	9.58
Granted	21,000	20.10
Exercised	(2,500)	1.75
Outstanding at December 31, 2002	94,000	$ 12.14

	OUTSTANDING AND EXERCISABLE OPTIONS AT DECEMBER 31, 2002		
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.88 - $ 3.75	15,000	1.0 years	$ 3.40
$ 6.87 - $ 9.00	30,000	5.0 years	$ 7.76
$12.19 - $17.54	28,000	8.0 years	$ 15.53
$20.10 - $20.10	21,000	9.3 years	$ 20.10

Under Unit’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. Unit may match each employee’s contribution, up to a specified maximum, in full or on a partial basis. The Company made discretionary contributions under the plan of 58,353, 35,016 and 87,452 shares of common stock and recognized expense of $595,000, $1,082,000 and $1,079,000 in 2000, 2001 and 2002, respectively.

Unit provides a salary deferral plan ("Deferral Plan") which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. Funds set aside in a trust to satisfy Unit’s obligation under the Deferral Plan at December 31, 2000, 2001 and 2002 totaled $1,536,000, $1,277,000 and $1,391,000, respectively. Unit recognizes payroll expense and records a liability at the time of deferral.

Effective January 1, 1997, Unit adopted a separation benefit plan (“Separation Plan”). The Separation Plan allows eligible employees whose employment with Unit is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against Unit in exchange for receiving the separation benefits. On October 28, 1997, Unit adopted a Separation Benefit Plan for Senior Management (“Senior Plan”). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Unit recognized expense of $558,000, $589,000 and $619,000 in 2000, 2001 and 2002, respectively, for benefits associated with anticipated payments from both separation plans.

Unit has entered into key employee change of control contracts with five of our executive officers. These severance contracts have an initial three-year term that is automatically extended for one year upon each anniversary, unless a notice not to extend is given by Unit. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive's terms and conditions for employment (including position, work location, compensation and benefits) will not be adversely changed during the three-year period after a change of control. If the executive's employment is terminated by the company (other than for cause, death or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and upon certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary

plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 7 - TRANSACTIONS WITH RELATED PARTIES

Unit formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2002, with a subsidiary of Unit serving as General Partner. Questa Oil and Gas Co. formed five private limited partnerships for 1981 to 1993. 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 Unit in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with Unit and Questa, respectively, in most drilling operations and most producing property acquisitions commenced by Unit or Questa for their own account during the period from the formation of the Partnerships through December 31 of each year. Unit repurchased the limited partner's interest in three of five Questa partnerships in the fourth quarter of 2000 and one of the Questa partnerships in the first quarter of 2001 and the four partnerships were dissolved. On December 31, 2002, Unit rolled up nine of the private limited partnerships and consolidated them into one partnership.

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

	2000	2001	2002
		(In thousands)	
Contract Drilling	$ 296	$ 416	$ 209
Well Supervision and Other Fees	$ 478	$ 498	$ 510
General and Administrative Expense Reimbursement	$ 192	$ 193	$ 210

Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party's behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable.

A subsidiary of Unit paid the Partnerships, for which Unit or a subsidiary is the general partner, $6,000, $3,000 and $1,000 during the years ended December 31, 2000, 2001 and 2002, respectively, for purchases of natural gas production.

NOTE 8 - SHAREHOLDER RIGHTS PLAN

Unit maintains a Shareholder Rights Plan (the "Plan") designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of Unit without offering fair value to all shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

Under the terms of the Plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from Unit one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by Unit or to purchase from an acquiring company certain shares of its common stock or the surviving company's common stock at 50 percent of its value.

The rights become exercisable 10 days after Unit learns that an acquiring person (as defined in the Plan) has acquired 15 percent or more of the outstanding common stock of Unit or 10 business days after the commencement of a tender offer, which would result in a person owning 15 percent or more of such shares. Unit can redeem the rights for $0.01 per right at any date prior to the earlier of (i) the close of business on the tenth day following the time Unit learns that a person has become an acquiring person or (ii) May 19, 2005 (the "Expiration Date"). The rights will expire on the Expiration Date, unless redeemed earlier by Unit.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Unit leases office space under the terms of operating leases expiring through January 31, 2007. Future minimum rental payments under the terms of the leases are approximately $663,000, $647,000, $192,000, $151,000 and $13,000 in 2003, 2004, 2005, 2006 and 2007, respectively. Total rent expense incurred by the Company was $535,000, $582,000 and $678,000 in 2000, 2001 and 2002, respectively.

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 Unit 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. Unit made repurchases of $14,000 and $1,000 in 2000 and 2002, respectively, for such limited partners' interests. No repurchases were made in 2001. Subsequent to the merger, in 2000, Unit also paid $17,000 for additional interest in two of the Questa limited partnerships and $1,980,000 for all the remaining interest in three other Questa partnerships. In 2001, Unit paid $15,000 for interests in two of the Questa limited partnerships and subsequently dissolved one of the Questa partnerships.

Unit is a party to various legal proceedings arising in the ordinary course of its business none of which, in management's opinion, will result in judgments which would have a material adverse effect on Unit's financial position, operating results or cash flows.

NOTE 10 - INDUSTRY SEGMENT INFORMATION

Unit 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 accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (Note 1). Management evaluates the performance of Unit's operating segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. Unit has natural gas production in Canada, which is not significant.

	2000	2001	2002
		(In thousands)	
Revenues:			
Contract drilling	$ 108,075	$ 167,042	$ 118,173
Oil and natural gas	92,016	90,237	67,959
Other	1,173	1,900	1,504
Total revenues	$ 201,264	$ 259,179	$ 187,636
Operating Income (1):			
Contract drilling	$ 12,025	$ 62,148	$ 12,151
Oil and natural gas	53,770	45,925	23,826
Total operating income	65,795	108,073	35,977
General and administrative expense	(6,560)	(8,476)	(8,712)
Interest expense	(5,136)	(2,818)	(973)
Other income (expense)- net	1,173	1,900	1,504
Income before income taxes	$ 55,272	$ 98,679	$ 27,796
Identifiable Assets (2):			
Contract drilling	$ 141,324	$ 183,471	$ 299,655
Oil and natural gas	198,251	220,476	261,440
Total identifiable assets	339,575	403,947	561,095
Corporate assets	6,713	13,306	17,068
Total assets	$ 346,288	$ 417,253	$ 578,163

	2000	2001	2002	
		(In thousands)		
Capital Expenditures:				
Contract drilling	$ 22,045	$ 51,280	$ 139,298	(3)
Oil and natural gas	39,884	56,933	58,778	
Other	3,324	539	516	
Total capital expenditures	$ 65,253	$ 108,752	$ 198,592	
Depreciation, Depletion, Amortization and Impairment:				
Contract drilling	$ 11,999	$ 13,888	$ 14,684	
Oil and natural gas	18,492	22,116	23,338	
Other	455	638	635	
Total depreciation, depletion, amortization and impairment	$ 30,946	$ 36,642	$ 38,657	

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

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

(3) Includes $7.7 million for goodwill and $2.2 million for deferred tax assets.

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2001 and 2002 is as follows:

	THREE MONTHS ENDED			
	MARCH 31	**JUNE 30**	**SEPTEMBER 30**	**DECEMBER 31**
	(In thousands except per share amounts)			
Year Ended December 31, 2001:				
Revenues	$ 70,443	$ 71,087	$ 68,399	$ 49,250
Gross profit(1)	$ 33,414	$ 32,091	$ 27,277	$ 15,291
Income before income taxes	$ 30,862	$ 29,070	$ 25,170	$ 13,577
Net income(2)	$ 19,172	$ 18,048	$ 15,631	$ 9,915
Earnings per common share:				
Basic (3)	$ 0.53	$ 0.50	$ 0.43	$ 0.28
Diluted	$ 0.53	$ 0.50	$ 0.43	$ 0.27
Year Ended December 31, 2002:				
Revenues	$ 38,730	$ 44,753	$ 48,272	$ 55,881
Gross profit(1)	$ 6,515	$ 10,295	$ 8,107	$ 11,060
Income before income taxes	$ 4,254	$ 8,297	$ 6,022	$ 9,223
Net income(2)	$ 2,642	$ 5,108	$ 3,708	$ 6,786
Earnings per common share:				
Basic (3)	$ 0.07	$ 0.14	$ 0.09	$ 0.16
Diluted (4)	$ 0.07	$ 0.14	$ 0.09	$ 0.16

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(1) Gross profit excludes other revenues, general and administrative expense and interest expense.

(2) The net income for the three months ended December 31, 2001 and 2002 includes a tax benefit of $1.5 million and $1.1 million, respectively,

relating to an increase in the estimated amount of statutory depletion carryforward.

(3) Due to the effect of rounding basic earnings per share for the year's four quarters does not equal the annual earnings per share.

(4) Due to the effect of price changes of Unit's stock, diluted earnings per share for the year's four quarters, which includes the effect of potential dilutive common shares calculated during each quarter, does not equal the annual diluted earnings per share, which includes the effect of such potential dilutive common shares calculated for the entire year.

NOTE 12 - OIL AND NATURAL GAS INFORMATION

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

	USA	CANADA	TOTAL
		(In thousands)	
2000:			
Capitalized costs:			
Proved properties	$ 338,159	$ 553	$ 338,712
Unproved properties	10,795	200	10,995
	348,954	753	349,707
Accumulated depreciation, depletion, amortization and impairment	(176,515)	(435)	(176,950)
Net capitalized costs	$ 172,439	$ 318	$ 172,757
Cost incurred:			
Unproved properties acquired	$ 5,522	$ 16	$ 5,538
Producing properties acquired	3,752	45	3,797
Exploration	2,409	-	2,409
Development	28,140	-	28,140
Total costs incurred	$ 39,823	$ 61	$ 39,884
2001:			
Capitalized costs:			
Proved properties	$ 391,216	$ 888	$ 392,104
Unproved properties	14,207	180	14,387
	405,423	1,068	406,491
Accumulated depreciation, depletion, amortization and impairment	(196,270)	(475)	(196,745)
Net capitalized costs	$ 209,153	$ 593	209,746
Cost incurred:			
Unproved properties acquired	$ 7,503	$ 21	$ 7,524
Producing properties acquired	1,419	-	1,419
Exploration	9,336	-	9,336
Development	38,359	295	38,654
Total costs incurred	$ 56,617	$ 316	$ 56,933

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	USA	CANADA	TOTAL
		(In thousands)	
2002:			
Capitalized costs:			
Proved properties	$ 448,331	$ 895	$ 449,226
Unproved properties	15,692	332	16,024
	464,023	1,227	465,250
Accumulated depreciation, depletion, amortization and impairment	(218,956)	(520)	(219,476)
Net capitalized costs	$ 245,067	$ 707	$ 245,774
Cost incurred:			
Unproved properties acquired	$ 5,330	$ 152	$ 5,482
Producing properties acquired	13,379	-	13,379
Exploration	6,591	-	6,591
Development	33,319	7	33,326
Total costs incurred	$ 58,619	$ 159	$ 58,778

The results of operations for producing activities are provided below.

	USA	CANADA	TOTAL
	(In thousands)		
2000:			
Revenues	$ 88,461	$ 110	$ 88,571
Production costs	(16,457)	(19)	(16,476)
Depreciation, depletion, amortization and impairment	(18,258)	(15)	(18,273)
	53,746	76	53,822
Income tax expense	(20,350)	(30)	(20,380)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 33,396	$ 46	$ 33,442
2001:			
Revenues	$ 86,810	$ 190	$ 87,000
Production costs	(18,636)	(23)	(18,659)
Depreciation, depletion and amortization	(19,756)	(40)	(19,796)
	48,418	127	48,545
Income tax expense	(17,621)	(40)	(17,661)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 30,797	$ 87	$ 30,884
2002:			
Revenues	$ 64,534	$ 87	$ 64,621
Production costs	(17,300)	(25)	(17,325)
Depreciation, depletion and amortization	(22,685)	(45)	(22,730)
	24,549	17	24,566
Income tax expense	(8,436)	(5)	(8,441)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 16,113	$ 12	$ 16,125

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 (unaudited):

	USA		**CANADA**		**TOTAL**	
	OIL BBLS	**NATURAL GAS MCF**	**OIL BBLS**	**NATURAL GAS MCF**	**OIL BBLS**	**NATURAL GAS MCF**
			(In thousands)			
2000:						
Proved developed and undeveloped reserves:						
Beginning of year	4,527	186,770	-	569	4,527	187,339
Revision of previous estimates	(45)	6,385	-	(82)	(45)	6,303
Extensions, discoveries and other additions	286	37,896	-	-	286	37,896
Purchases of minerals in place	229	4,893	-	-	229	4,893
Sales of minerals in place	(326)	(1,509)	-	-	(326)	(1,509)
Production	(488)	(19,239)	-	(46)	(488)	(19,285)
End of Year	4,183	215,196	-	441	4,183	215,637
Proved developed reserves:						
Beginning of year	3,583	144,992	-	467	3,583	145,459
End of year	3,222	162,718	-	389	3,222	163,107
2001:						
Proved developed and undeveloped reserves:						
Beginning of year	4,183	215,196	-	441	4,183	215,637
Revision of previous estimates	(214)	(24,253)	-	(7)	(214)	(24,260)
Extensions, discoveries and other additions	861	54,521	-	-	861	54,521
Purchases of minerals in place	8	1,246	-	-	8	1,246
Sales of minerals in place	(3)	(26)	-	-	(3)	(26)
Production	(492)	(18,819)	-	(45)	(492)	(18,864)
End of Year	4,343	227,865	-	389	4,343	228,254
Proved developed reserves:						
Beginning of year	3,222	162,718	-	389	3,222	163,107
End of year	2,753	150,419	-	338	2,753	150,757

	USA		CANADA		TOTAL	
	OIL BBLS	NATURAL GAS MCF	OIL BBLS	NATURAL GAS MCF	OIL BBLS	NATURAL GAS MCF
			(In thousands)			
2002:						
Proved developed and undeveloped reserves:						
Beginning of year	4,343	227,865	-	389	4,343	228,254
Revision of previous estimates	(166)	(10,543)	-	(31)	(166)	(10,574)
Extensions, discoveries and other additions	230	29,541	-	-	230	29,541
Purchases of minerals in place	192	16,558	-	-	192	16,558
Sales of minerals in place	(30)	-	-	-	(30)	-
Production	(473)	(18,927)	-	(41)	(473)	(18,968)
End of Year	4,096	244,494	-	317	4,096	244,811
Proved developed reserves:						
Beginning of year	2,753	150,419	-	338	2,753	150,757
End of year	2,951	168,049	-	317	2,951	168,366

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. Unit utilizes Ryder Scott Company, independent petroleum consultants, to review its reserves as prepared by its 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 previously explained. 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 (unaudited):

	USA	CANADA	TOTAL
		(In thousands)	
2000:			
Future cash flows	$2,260,796	$ 4,155	$2,264,951
Future production and development costs	(484,900)	(433)	(485,333)
Future income tax expenses	(574,099)	(1,099)	(575,198)
Future net cash flows	1,201,797	2,623	1,204,420
10% annual discount for estimated timing of cash flows	(527,210)	(1,184)	(528,394)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 674,587	$ 1,439	$ 676,026
2001:			
Future cash flows	$ 676,051	$ 975	$ 677,026
Future production and development costs	(279,499)	(341)	(279,840)
Future income tax expenses	(94,037)	(134)	(94,171)
Future net cash flows	302,515	500	303,015
10% annual discount for estimated timing of cash flows	(125,238)	(194)	(125,432)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 177,277	$ 306	$ 177,583
2002:			
Future cash flows	$1,256,434	$ 1,400	$1,257,834
Future production and development costs	(386,206)	(309)	(386,515)
Future income tax expenses	(250,413)	(233)	(250,646)
Future net cash flows	619,815	858	620,673
10% annual discount for estimated timing of cash flows	(275,015)	(344)	(275,359)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 344,800	$ 514	$ 345,314

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

	USA	CANADA	TOTAL
		(In thousands)	
2000:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (72,005)	$ (91)	$ (72,096)
Net changes in prices and production costs	647,313	1,854	649,167
Revisions in quantity estimates and changes in production timing	44,991	(324)	44,667
Extensions, discoveries and improved recovery, less related costs	184,624	-	184,624
Purchases of minerals in place	23,144	-	23,144
Sales of minerals in place	(3,469)	-	(3,469)
Accretion of discount	19,881	51	19,932
Net change in income taxes	(293,357)	(581)	(293,938)
Other - net	(43,760)	53	(43,707)
Net change	507,362	962	508,324
Beginning of year	167,225	477	167,702
End of year	$ 674,587	$ 1,439	$ 676,026
2001:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (68,174)	$ (167)	$ (68,341)
Net changes in prices and production costs	(768,295)	(1,600)	(769,895)
Revisions in quantity estimates and changes in production timing	(32,705)	13	(32,692)
Extensions, discoveries and improved recovery, less related costs	54,127	-	54,127
Purchases of minerals in place	1,217	-	1,217
Sales of minerals in place	(220)	-	(220)
Accretion of discount	99,953	205	100,158
Net change in income taxes	271,421	524	271,945
Other - net	(54,634)	(108)	(54,742)
Net change	(497,310)	(1,133)	(498,443)
Beginning of year	674,587	1,439	676,026
End of year	$ 177,277	$ 306	$ 177,583

	USA	CANADA	TOTAL
		(In thousands)	
2002:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (47,230)	$ (62)	$ (47,292)
Net changes in prices and production costs	230,934	363	231,297
Revisions in quantity estimates and changes in production timing	(49,000)	(110)	(49,110)
Extensions, discoveries and improved recovery, less related costs	60,957	-	60,957
Purchases of minerals in place	23,334	-	23,334
Sales of minerals in place	(150)	-	(150)
Accretion of discount	23,080	39	23,119
Net change in income taxes	(84,843)	(59)	(84,902)
Other - net	10,441	37	10,478
Net change	167,523	208	167,731
Beginning of year	177,277	306	177,583
End of year	$ 344,800	$ 514	$ 345,314

Unit'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 spot prices of oil ($29.70) and natural gas ($4.42) 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 Unit's properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to Unit'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.

REPORT OF INDEPENDENT ACCOUNTANTS

The Shareholders and Board of Directors
Unit Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in shareholders' equity and cash flows present fairly in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2001 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the accompanying financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. 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 of these financial statements in accordance with auditing standards generally accepted in the United States of America which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 19, 2003

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*

None.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The table below and accompanying footnotes set forth certain information concerning each of our executive officers. Unless otherwise indicated, each has served in the positions set forth for more than five years. Executive officers are elected for a term of one year. There are no family relationships between any of the persons named.

NAME	AGE	POSITION
John G. Nikkel	68	President, Chief Executive Officer, Chief Operating Officer and Director
Earle Lamborn	68	Senior Vice President, Drilling and Director
Philip M. Keeley	61	Senior Vice President, Exploration and Production
Larry D. Pinkston	48	Executive Vice President, Treasurer and Chief Financial Officer
Mark E. Schell	45	Senior Vice President, General Counsel and Secretary

Mr. Nikkel joined Unit in 1983 as its President and a director. On July 1, 2001 Mr. Nikkel was elected to the additional office of Chief Executive Officer. From 1976 until January 1982 when he co-founded Nike Exploration Company, Mr. Nikkel was an officer and director of Cotton Petroleum Corporation, serving as the President of Cotton from 1979 until his departure. Prior to joining Cotton, Mr. Nikkel was employed by Amoco Production Company for 18 years, last serving as Division Geologist for Amoco's Denver Division. Mr. Nikkel presently serves as President and a director of Nike Exploration Company. From August 16, 2000 until August 23,2002 Mr. Nikkel also served as a director of Shenandoah Resources LTD., a Canadian company. Shenandoah Resources LTD. filed for creditors protection (Initial Application Order Under The Companies' Creditor Arrangement Act) in April, 2002 with the Court of Queen's Bench of Alberta, Judicial District of

Calgary. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Lamborn has been actively involved in the oil field for over 50 years, joining Unit's predecessor in 1952 prior to its becoming a publicly-held corporation. He was elected Vice President, Drilling in 1973 and to his current position as Senior Vice President, Drilling and director in 1979.

Mr. Keeley joined Unit in November 1983 as Senior Vice President, Exploration and Production. Prior to that time, Mr. Keeley co-founded (with Mr. Nikkel) Nike Exploration Company in January 1982 and, until November 2001, served as Executive Vice President and a director of that company. From 1977 until 1982, Mr. Keeley was employed by Cotton Petroleum Corporation, serving first as Manager of Land and from 1979 as Vice President and a director. Before joining Cotton, Mr. Keeley was employed for four years by Apexco, Inc. as Manager of Land and prior thereto he was employed by Texaco, Inc. for nine years. He received a Bachelor of Arts degree in Petroleum Land Management from the University of Oklahoma.

Mr. Pinkston joined Unit in December 1981. He had served as Corporate Budget Director and Assistant Controller prior to being appointed Controller in February 1985. He has been Treasurer since December 1986 and was elected to the position of Vice President and Chief Financial Officer in May 1989. In December 2002, he was elected to the additional position of Executive Vice President. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

Mr. Schell joined Unit in January 1987, as its Secretary and General Counsel. In December 2002, he was elected to the additional position as Senior Vice President. From 1979 until joining Unit, Mr. Schell was Counsel, Vice President and a member of the Board of Directors of C&S Exploration, Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa Law School. He is a member of the Oklahoma and American Bar Association as well as being a member of the American Corporate Counsel Association and the American Society of Corporate Secretaries.

The balance of the information required in this Item 10 is incorporated by reference from Unit's Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company's 2002 annual meeting of stockholders.

Item 11. ***Executive Compensation***
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Information required by this item is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with Unit’s 2003 annual meeting of stockholders.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management***
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Information required by this item is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with Unit’s 2003 annual meeting of stockholders.

Item 13. ***Certain Relationships and Related Transactions***
-------- --

Information required by this item is incorporated by reference from Unit’s Proxy Statement to be filed with the Securities and Exchange Commission in connection with Unit’s 2003 annual meeting of stockholders.

ITEM 14. Controls and Procedures
-------- ----------------------

a) Evaluation of disclosure controls and procedures. Within the 90 day period prior to the filing date of this Annual Report on Form 10-K, our management, under the supervision and with the participation of the our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer believe that:

i) the company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the company in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and

ii) the company's disclosure controls and procedures operate such that important information flows to appropriate collection and disclosure points in a timely manner and is effective to ensure that such information is accumulated and communicated to the company's management, and made known to our Chief Executive Officer and Chief Financial Officer, particularly during the period when this Annual Report on Form 10-K was prepared, as appropriate to allow timely decision regarding the required disclosure.

b) Changes in internal controls. There have been no significant changes in the company's internal controls or in other factors that could significantly affect the company's internal controls subsequent to their evaluation, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(a) Financial Statements, Schedules and Exhibits:

1. Financial Statements:

Included in Part II of this report:
- Consolidated Balance Sheets as of December 31, 2001 and 2002
- Consolidated Statements of Operations for the years ended December 31, 2000, 2001 and 2002
- Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2000, 2001 and 2002
- Consolidated Statements of Cash Flows for the years ended December 31, 2000, 2001 and 2002
- Notes to Consolidated Financial Statements
- Report of Independent Accountants

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 2000, 2001 and 2002:
- Schedule II - Valuation and Qualifying Accounts and Reserves

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

The exhibit numbers in the following list correspond to the numbers assigned such exhibits in the Exhibit Table of Item 601 of Regulation S-K.

3. Exhibits:

2.6.1 Amended and Restated Stock Purchase Agreement dated as of June 24, 2002 by and among Unit Corporation, George B. Kaiser and Kaiser Francis Oil Company (incorporated herein by reference to Exhibit 99.1 to Form 8-K dated August 27,2002).

2.6.2 Amended and Restated Share Purchase Agreement dated as of June 24, 200, by and among Unit Corporation, Kaiser Francis Charitable Income Trust B and Kaiser Francis Oil Company (incorporated herein by reference to Exhibit 99.2 to Form 8-K dated August 27,2002).

3.1 Restated Certificate of Incorporation of Unit Corporation (file as Exhibit 3.1 to Form S-3 (file No. 333-83551), which is incorporated herein by reference).

3.2 By-Laws of Unit Corporation (filed as Exhibit 3.2 to Unit's Form 8-K to Form S-3 (file No. 333-83551), which is incorporated herein by reference).

4.2.3 Form of Common Stock Certificate (filed as Exhibit 4.1 on Form S-3 as S.E.C. File No. 333-83551, which is incorporated herein by reference).

4.2.6 Rights Agreement between Unit Corporation and Chemical Bank, as Rights Agent (filed as Exhibit 1 to Unit's Form 8-A filed with the S.E.C. on May 23, 1995, File No. 1-92601 and incorporated herein by reference).

4.2.7 First Amendment of Rights Agreement dated May 19, 1995, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed as Exhibit 4 to Unit's Form 8-K dated August 23, 2001, which is incorporated herein by reference).

4.2.8 Second Amendment of the Rights Agreement, dated August 14, 2002, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed herein).

10.1.25 Loan Agreement dated July 24, 2001 (filed as an Exhibit to Unit's Quarterly Report under cover of Form 10-Q for the quarter ended June 30, 2001, which is incorporated herein by reference).

10.2.2 Unit 1979 Oil and Gas Program Agreement of Limited Partnership (filed as Exhibit I to Unit Drilling and Exploration Company's Registration Statement on Form S-1 as S.E.C. File No. 2-66347, which is incorporated herein by reference).

10.2.10 Unit 1984 Oil and Gas Program Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1984 Oil and Gas Program's Registration Statement Form S-1 as S.E.C. File No. 2-92582, which is incorporated herein by reference).

10.2.21* Unit Drilling and Exploration Employee Bonus Plan (filed as Exhibit 10.16 to Unit's Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).

10.2.22* The Company's Amended and Restated Stock Option Plan (filed as an Exhibit to Unit’s Registration Statement on Form S-8 as S.E.C. File No’s. 33-19652, 33-44103 and 33-64323 which is incorporated herein by reference).

10.2.23* Unit Corporation Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-49724, which is incorporated herein by reference).

10.2.24* Unit Corporation Employees' Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).

10.2.25 Unit Consolidated Employee Oil and Gas Limited Partnership Agreement. (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

10.2.27* Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

10.2.30* Separation Benefit Plan of Unit Corporation and Participating Subsidiaries (filed as an Exhibit to Unit’s Annual Report under the cover of Form 10-K for the year ended December 31, 1996, which is incorporated herein by reference).

10.2.32 Unit Corporation Separation Benefit Plan for Senior Management (filed as an Exhibit to Unit’s Quarterly Report under cover of Form 10-Q for the quarter ended September 30, 1997, which is incorporated herein by reference).

10.2.35 Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under the cover of Form 10-K for the year ended December 31, 1999).

10.2.36* Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 333-38166, which is incorporated herein by reference).

10.2.37* Unit Corporation's Amended and Restated Stock Option Plan (filed as an Exhibit to Unit’s Registration Statement on Form S-8 as S.E.C. File No. 333-39584 which is incorporated herein by reference).

10.2.38 Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual

Report under the cover of Form 10-K for the year ended December 31, 2000).

10.2.39* Form of Unit Corporation Key Employee Change of Control Contract (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).

10.2.40 Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as Exhibit 10 to Unit's Form 8-K dated August 23, 2001, which is incorporated herein by reference).

10.2.41 Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 21, 2001).

10.2.42 Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herein).

21 Subsidiaries of the Registrant (filed herewith).

23 Consent of Independent Accountants (filed herewith).

99.2 Separation Agreement, dated May 11, 2001, between the Registrant and Mr. Kirchner (filed as Exhibit 99.A4 to Unit's Form 8-K dated May 18, 2001, which is incorporated herein by reference).

* Indicates a management contract or compensatory plan identified pursuant to the requirements of Item 14 of Form 10-K.

(b) Reports on Form 8-K:

On November 5, 2002 we filed a report on Form 8-K under item 9. This report disclosed that the Principal Executive Officer, John G. Nikkel, and Principal Financial Officer, Larry D. Pinkston, of Unit Corporation, had filed with the SEC certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Schedule II

UNIT CORPORATION AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

Description	Balance at Beginning of Period	Additions Charged to Costs & Expenses	Deductions & Net Write-Offs	Balance at End of Period
		(In thousands)		
Year ended December 31, 2000	$ 583	$ 350	$ 14	$ 919
Year ended December 31, 2001	$ 919	$ -	$ 315	$ 604
Year ended December 31, 2002	$ 604	$ 603	$ 4	$ 1,203

Deferred Tax Asset Valuation Allowance:

Description	Balance at Beginning of Period	Additions	Deductions	Balance At End of Period
		(In thousands)		
Year ended December 31, 2000	$ 335	$ -	$ 335	$ -
Year ended December 31, 2001	$ -	$ -	$ -	$ -
Year ended December 31, 2002	$ -	$ -	$ -	$ -

SIGNATURES

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 12, 2003 By: /s/ John G. Nikkel

JOHN G. NIKKEL
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of March, 2003.

Name	Title
/s/ King P. Kirchner **KING P. KIRCHNER**	Chairman of the Board and Director
/s/ John G. Nikkel **JOHN G. NIKKEL**	President and Chief Executive Officer Chief Operating Officer, Director
/s/ Earle Lamborn **EARLE LAMBORN**	Senior Vice President, Drilling, Director
/s/ Larry D. Pinkston **LARRY D. PINKSTON**	Executive Vice President, Chief Financial Officer and Treasurer
/s/ Stanley W. Belitz **STANLEY W. BELITZ**	Controller
/s/ J. Michael Adcock **J. MICHAEL ADCOCK**	Director
/s/ Don Cook **DON COOK**	Director
/s/ William B. Morgan **WILLIAM B. MORGAN**	Director
/s/ John S. Zink **JOHN S. ZINK**	Director
/s/ John H. Williams **JOHN H. WILLIAMS**	Director

CERTIFICATIONS

I, John G. Nikkel, certify that:

1. I have reviewed this annual report on Form 10-K of Unit Corporation;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

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

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 12, 2003

By: /s/ John G. Nikkel

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

CERTIFICATIONS

I, Larry D. Pinkston, certify that:

1. I have reviewed this annual report on Form 10-K of Unit Corporation;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

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

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 12, 2003

By: /s/ Larry D. Pinkston

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

EXHIBIT INDEX

Exhibit No.	Description	Page
4.2.8	Second Amendment of the Rights Agreement, dated August 14, 2002, between the Company and Mellon Shareholder Services LLC, as Rights Agent.	
10.2.42	Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.	
21	Subsidiaries of the Registrant.	
23	Consent of Independent Accountants.	