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, 2000

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.

Aggregate Market Value of the Voting Stock Held By Non-affiliates on March 16 2001 - $467,971,160

Number of Shares of Common Stock Outstanding on March 16 2001 - 35,934,791

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 2, 2001 are incorporated by reference in Part III.

FORM 10-K
UNIT CORPORATION

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2000

PART I

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GENERAL

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. Today our contract drilling operations and our exploration and production operations are carried out primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins and the Texas Gulf Cost. Our contract drilling operations are also engaged in the East Texas and Rocky Mountain region.

Our executive offices are located at 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136; telephone number (918) 493-7700. We also have regional offices in Oklahoma City, Oklahoma, Woodward, Oklahoma, Booker, Texas, Houston, Texas and Casper, Wyoming. When used in this report, the terms Corporation, Unit, our, we and its refer to Unit Corporation and, at times, Unit Corporation and/or one or more of its subsidiaries.

LAND CONTRACT DRILLING OPERATIONS

We drill onshore natural gas and oil wells for a wide range of customers through our wholly owned subsidiary Unit Drilling Company. 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. We conduct an active maintenance and replacement program under which components are upgraded on an individual basis. 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, are replaced or rebuilt on a periodic basis, while other components, such as the substructure, mast and drawworks, can be utilized 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.

On September 30, 1999, we completed the acquisition of 13 land drilling rigs from Parker Drilling Company and Parker Drilling Company North America, Inc., for $40 million and one million shares of our common stock.

On December 29, 2000, we purchased a 750 horsepower diesel electric rig with a 13,500 foot depth capacity for $3.2 million and at December 31, 2000, we were completing the construction of two additional rigs.

At December 31, 2000, our drilling rig fleet consisted of 50 rigs with depth capacities ranging from 9,500 to 40,000 feet of which 34 were located in the Anadarko and Arkoma Basins of Oklahoma and Texas while nine were located in the East Texas and Gulf Coast Region and seven in the Rocky Mountain region.

In January 2001, we purchased a 1,000 horse power diesel electric rig with a 16,000 foot depth capacity for $3.2 million. This new rig is working in the Gulf Coast region. In February 2001, we purchased a 1,000 horse power mechanical rig, also with a 16,000 foot depth capacity, for $2.5 million. This rig will be moved from Alaska to the Rocky Mountain region in the second quarter of 2001. The addition of these two rigs brings our fleet to 52 rigs.

At present, we do not have a shortage of drilling rig related equipment. During 1996 and through 1997, we increased our drill pipe acquisitions since certain grades of drill pipe were in high demand due to increased rig utilization. However, at any given time our ability to use all of our rigs will depend on the availability of qualified labor, drilling supplies and equipment as well as demand.

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

	Year Ended December 31,				
	1996	**1997**	**1998**	**1999**	**2000**
Number of Rigs Owned At End of Period	24.0	34.0 (1)	34.0	47.0 (2)	50.0 (3
Average Number of Rigs Owned During Period	22.7	25.1	34.0	37.3	47.0
Average Number of Rigs Utilized (4)	14.7	20.0	22.9	23.1	39.8
Utilization Rate (4)	65%	80%	67%	62%	85%
Average Revenue Per Day (5)	$5,351	$6,309	$6,394	$6,582	$7,432
Total Footage Drilled (Feet in 1000's)	1,468	1,736	2,203	2,211	3,650
Number of Wells Drilled	130	167	198	197	316

(1) Includes 10 rigs acquired in the fourth quarter of 1997.

(2) Includes 13 rigs acquired in September 1999.

(3) Includes one rig acquired at the 2000 year-end and two additional rigs that were completing construction.

(4) Utilization rates are based on a 365-day year and are calculated by dividing the number of rigs utilized by the total number of rigs owned during the period, including stacked rigs. A rig is considered utilized when it is operating or being moved, assembled or dismantled under contract.

(5) Represents total revenues from contract drilling operations divided by the total number of days rigs were being utilized for the period.

As of February 7, 2001, 47 of our drilling rigs were operating under contract.

The following table sets forth, as of March 16, 2001, the type and approximate depth capability of each of our drilling rigs:

Rig#	Type	Approximate Depth Capability (feet)
1	BDW 650	13,000
2	BDW 650	13,000
3	BDW 650	13,500
4	Gardner Denver 500	12,500
5	U-15 Unit Rig	11,000
6	BDW 800	17,000
8	Gardner Denver 800	16,000
9	BDW 800	17,000
10	BDW 450T	9,500
11	Gardner Denver 700	15,000
12	BDW 800	16,000
14	Gardner Denver 700	15,000
15	Mid-Continent 914-C	20,000
16	U-15 Unit Rig	11,000
17	Brewster N-75	15,000
18	BDW 650	12,500
19	Gardner Denver 500	12,000
20	Gardner Denver 700	15,000
21	Gardner Denver 700	15,000
22	BDW 800	16,000
23	Gardner Denver 700	14,000
24	Gardner Denver 700	14,000
25	Gardner Denver 700	15,000
26	National 610 E	13,500
27	BDW 650	13,000
28	Continental Emsco D-3	16,000
29	Brewster N-75A	15,000
30	BDW 1350-M	20,000
31	Shufelt	12,500
32	Brewster N-75	15,000
33	BDW 800	16,000
34	National 110-UE	20,000
35	Continental Emsco C-1	20,000
36	Gardner Denver 1500-E	25,000
37	Mid-Continent 914-EC	20,000
38	Mid-Continent 1220-EB	25,000
39	Mid-Continent U-36-A	12,000
40	BDW 800	16,000
112	Ideco E-3000	25,000
166	OIME E-3000	25,000
180	OIME E-3000	30,000
182	OIME E-3000	30,000
184	OIME E-3000	30,000
201	OIME E-4000	40,000
203	OIME E-2000	25,000
232	Continental Emsco D-3 II	16,000
233	Continental Emsco C-1 III	20,000
234	Continental Emsco D-3 II	16,000
235	Continental Emsco C-1 II	20,000
236	Gardner Denver 800	16,000
237	Continental Emsco C-1 II	20,000
254	OIME E-2000	25,000

During most of the past 17 years, our contract drilling operations encountered significant competition due to depressed levels of activity. In the last half of 1999 and throughout 2000, as oil and natural gas prices began to increase, the demand for our contract drilling services increased. Although we experienced an increase in demand for our drilling services and our dayrates and utilization have increased, we anticipate that competition within the industry will, for the foreseeable future, continue to adversely affect us.

Drilling Contracts. Most of our drilling contracts are obtained through competitive bidding. Generally, our contracts are for a single well with the terms and rates varying depending upon the nature and duration of the work, the equipment and services supplied and other matters. The contracts obligate us to 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. We generally indemnify our customers against certain types of claims by our employees and claims arising from surface pollution caused by spills of fuel, lubricants and other solvents within our control. Customers generally indemnify us against claims arising from other surface and subsurface pollution other than claims resulting from our gross negligence.

Our contracts generally compensate us on a daywork, footage or turnkey basis with additional compensation for special risks and unusual conditions. Under daywork contracts, we provide the drilling rig with the required personnel to the operator who supervises the drilling of the contracted well. Our compensation is based on a negotiated rate for each day the rig is utilized. Footage contracts usually require us to bear some of the drilling costs in addition to providing the rig. We are compensated on a negotiated rate, per foot drilled, upon completion of the well. Under turnkey contracts, we contract to drill a 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 compensated when the contract provisions have been satisfied.

Turnkey drilling operations, in particular, might result in losses if we underestimate the costs of drilling a well or if unforeseen events occur. To date, we have not experienced significant losses in performing turnkey contracts. For 2000, turnkey revenue represented approximately 9 percent of our contract drilling revenues as compared to 21 percent for 1999 and we did not have any turnkey contracts in progress at December 31, 2000. Because the proportion of turnkey drilling is dictated by market conditions and the desires of customers using our services, we can't predict whether the portion of drilling conducted on a turnkey basis will increase or decrease in the future.

Customers. During 2000, 10 contract drilling customers accounted for approximately 42 percent of our total contract drilling revenues.

Approximately 4 percent of our total contract drilling revenues were generated from drilling 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).

Further information relating to contract drilling operations is presented in Notes 1, 2 and 10 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

OIL AND NATURAL GAS OPERATIONS

In 1979, we began to develop our exploration and production operations to diversify our contract drilling revenues. Our wholly owned subsidiary, Unit Petroleum Company, conducts our exploration and production activities.

As of December 31, 2000, we had estimated net proved reserves of 4,183 Mbbls and 215,637 MMcf. Our producing oil and natural gas interests, undeveloped leaseholds and related assets are located primarily 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. As of December 31, 2000, we had an interest in a total of 2,887 wells in the United States, 667 of which we served as the operator. We also had an interest in 64 wells located in Canada. Our technical staff generates the majority of our development and exploration prospects. When we are the operator of a property, we generally employ our own drilling rigs and our own engineering staff supervises the drilling operation.

We intend to continue the growth in our oil and natural gas operations utilizing funds generated from operations and our bank loan agreement.

Well and Leasehold Data. The tables below set forth certain information regarding our oil and natural gas exploration and development drilling activities for the periods indicated:

	Year Ended December 31,					
	1998		1999		2000	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploratory:						
Oil	-	-	-	-	-	-
Natural gas	-	-	-	-	2	1.63
Dry	1	.26	-	-	-	-
Total	1	.26	-	-	2	1.63
Development:						
Oil	6	1.13	1	.48	7	1.45
Natural gas	62	22.71	55	19.23	75	28.51
Dry	27	11.85	10	5.47	17	8.56
Total	95	35.69	66	25.18	99	38.52
Oil and Natural Gas Wells Producing or Capable of Producing:						
Oil - USA	841	214.70	783	224.10	799	278.06
Oil - Canada	-	-	-	-	-	-
Gas - USA	1,960	370.70	1,950	403.50	2,088	431.11
Gas - Canada	64	1.60	64	1.60	64	1.60
Total	2,865	587.00	2,797	629.20	2,951	710.77

On February 7, 2001, Unit was participating in the drilling of 4 gross (2.36 net) wells in the United States.

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

	Developed Acreage		Undeveloped Acreage	
	Gross	**Net**	**Gross**	**Net**
1998:				
USA	628,241	142,543	52,958	35,371
Canada	39,040	976	22,763	22,763
	667,281	143,519	75,721	58,134
1999:				
USA	548,011	142,472	55,989	35,245
Canada	39,040	976	25,293	25,293
Total	587,051	143,448	81,282	60,538
2000:				
USA	564,780	153,507	61,487	39,480
Canada	39,040	976	26,243	13,121
Total	603,820	154,463	87,730	52,601

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 periods indicated:

	Year Ended December 31,		
	1998	**1999**	**2000**
Average Sales Price per Barrel of Oil Produced:			
USA	$ 12.77	$ 17.48	$ 26.95
Canada	-	-	-
Average Sales Price per Mcf of Natural Gas Produced:			
USA	$ 1.91	$ 2.05	$ 3.91
Canada	$ 1.46	$ 1.81	$ 2.39
Oil Production (Mbbls):			
USA	486	424	488
Canada	-	-	-
Total	486	424	488
Natural Gas Production (MMcf):			
USA	17,694	17,402	19,239
Canada	38	35	46
Total	17,732	17,437	19,285
Average Production Expense per Equivalent Mcf:			
USA	$ .62	$ .59	$ .74
Canada	$ .54	$ .56	$ .42

Reserves. The following table sets forth our estimated proved developed and undeveloped oil and natural gas reserves at the end of each of the years indicated:

	Year Ended December 31,		
	1998	**1999**	**2000**
Oil (Mbbls):			
USA	3,629	4,527	4,183
Canada	-	-	-
Total	3,629	4,527	4,183
Natural gas (MMcf):			
USA	175,884	186,770	215,196
Canada	523	569	441
Total	176,407	187,339	215,637

Further information relating to oil and natural gas operations is presented in Notes 1, 10 and 12 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

VOLATILE NATURE OF OUR OIL AND NATURAL GAS MARKETS; FLUCTUATIONS IN PRICES

Our revenues, operating results, cash flows and future rate of growth are significantly affected by the prevailing prices for natural gas and oil. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile. Oil and natural gas prices increased substantially in the last half of 1999 and throughout 2000. However, and despite the recent price improvements, it is possible that such prices could again decline. Price declines had a significant negative impact on our financial results for 1998 and the first six months of 1999. We incurred a net loss for the two quarterly periods ending March 31 and June 30, 1999 before incurring net income for the two quarterly periods ending September 30 and December 31, 1999. Although we had net income for the twelve months ended December 31, 1999 and significant increases in net income in 2000, depressed prices in the future would, as noted, have a negative impact on our future financial results. Because our oil and natural gas reserves are predominantly natural gas, changes in natural gas prices would have a disproportionate impact on our financial results.

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;
- 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 oil and condensate 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 original terms ranging from one month to several years at prices primarily determined on a daily basis. Most of these contracts contain provisions for readjustment of price, termination and other terms customary in the industry.

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 the 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 charged for our rigs. With the increase in oil and natural gas prices in the last half of 1999 and all of 2000 our dayrates and rig utilization have increased substantially.

Although oil and natural gas prices have recently improved, we expect that in the near term our customers will continue a cautious approach to exploration and development spending until price gains prove to be sustainable. Decreases from current oil and natural gas prices would depress the level of exploration and production activity. This in turn would likely result in a decline in our contract drilling revenues, cash flows and profitability. As a result, the future demand for our drilling services is uncertain.

COMPETITION

All of our lines of 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. As a result of the increase in demand for onshore contract drilling services over the past year and a half, previous surpluses of certain types of drilling rigs in the industry have been eliminated and the inventories of certain components such as specific grades of drill pipe have been depleted from continued use. 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 are more experienced in the exploration for and production of oil and natural gas than we are.

OIL AND NATURAL GAS PROGRAMS

Our subsidiary, Unit Petroleum Company, serves as the general partner of four oil and gas limited partnerships and 12 employee oil and gas limited partnerships. Each year we form an employee partnership which acquires an interest, ranging from 2.5% to 15% of our interest, in most oil and natural gas drilling activities and purchases of producing oil and natural gas properties that we do that year. The limited partners in the employee partnerships are either employees or directors of Unit or its subsidiaries. Our subsidiary, Questa Oil and Gas Co., also formed five private limited partnerships from 1981 to 1993. We repurchased the limited partner’s interest in three of five of the Questa partnerships in the fourth quarter of 2000 and the three partnerships were dissolved.

Under the terms of the 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 eliminate entirely 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 done pursuant to contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. Although we have no formal procedures for resolving such conflicts, 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 February 7, 2000, we had approximately 1,038 employees in our land contract drilling operations, 54 employees in our oil and natural gas operations and 52 in our general corporate area. None of our employees are represented by 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 many hazards inherent in the drilling industry, including 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 subject to these and 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, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract for some of these risks. To the extent that we are unable to transfer these risks to drilling customers by contract or indemnification agreements, we seek protection through insurance. However, we cannot assure you that our insurance or our indemnification agreements, if any, will adequately protect us against liability from all of the consequences of the hazards described above. 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 cannot assure you that insurance will be available 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.

The 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 are depleted, 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 oil and natural gas production and lower revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account through exploitation, development and exploration. We have conducted such activities on our existing oil and natural gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. Low prices of oil and natural gas may further limit the kinds of reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

GOVERNMENTAL REGULATIONS

The production and sale of oil and natural gas is highly affected by various state and federal regulations. 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 was 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 being 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 was not affected by the Decontrol Act.

Our sales of natural gas are 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 were 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 was required to be divested 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 are now required to 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. It remains to be seen 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 is 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 can be 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 frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with those laws.

SAFE HARBOR STATEMENT OF FURTHER ACTIVITY

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

- year 2001 plans;
- the amount and nature of future capital expenditures;
- wells to be drilled or reworked;
- oil and natural gas prices and demand;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and infill drilling potential;
- drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- business strategy;
- production of oil and natural gas reserves;
- expansion and growth of our business and operations; and
- drilling rig utilization, revenues and costs.

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

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 2001 and beyond to differ materially from those that may be set forth 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 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 to be received 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 that may be based 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 upon the results of our operations for 2000 we estimate that a change of $0.10/Mcf in the average price of natural gas and a change of $1.00/Bbl in the price of crude oil throughout such period would have resulted in approximate changes in net income before income taxes of $1,797,000 and $455,000, respectively. During 2000, 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.

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 a project to be abandoned 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 and Well Performance

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 should not be considered as 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 are 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 will be 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, which is required by the SEC to be used 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 the ceiling is exceeded, even if prices were 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 our growth in drilling operations and our active exploration, development and exploitation 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. As a result of our significant working capital requirements, we currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2000, our long-term debt outstanding was $54.0 million. As of December 31, 2000, 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 $70 million to reduce cost. The amount outstanding under our bank loan agreement at December 31, 2000 was $52.0 million.

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

- limit funds available for financing 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. We cannot assure you that we will be able to meet our debt service requirements. In addition, lower oil and natural gas prices could result in future reductions in the amount available for borrowing under our bank loan agreement, reducing our liquidity and even triggering mandatory loan repayments.

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 cannot assure you that we would have sufficient funds available or could 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 undertaken by us at any given time and the cash flow received by us. Generally, the costs incurred by us in our normal operations 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 2000.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol "UNT." The following table sets forth the high and low sale prices per share of our common stock as reported in the New York Stock Exchange composite transactions, for the periods indicated:

	1999		2000	
QUARTER	**High**	**Low**	**High**	**Low**
First	$ 7	$ 3 1/2	$ 11 1/2	$ 6 5/8
Second	$ 8 1/4	$ 4 7/8	$ 14 9/16	$ 9
Third	$ 9	$ 6 3/4	$ 16 1/4	$ 11 13/16
Fourth	$ 7 3/4	$ 4 7/8	$ 19 7/16	$ 12 3/8

As of February 7, 2001 our common stock was held by 2,158 holders of record.

We have not declared nor paid any cash dividends on shares of our common stock since organization and currently intend to continue our policy of retaining earnings from our operations. We are prohibited by certain loan agreement provisions from declaring and paying dividends (other than stock dividends) during any fiscal year in excess of 25 percent of our consolidated net income of the preceding fiscal year, and only if working capital provided from operations during the prior year is equal to or greater than 175 percent of current maturities of long-term debt at the end of the prior year.

Item 6. *Selected Financial Data*

	Year Ended December 31,				
	1996 (1)	1997 (1)	1998 (1)	1999 (1)	2000
	(In thousands except per share amounts)				
Revenues	$ 75,751	$ 96,478	$ 97,274	$ 102,352	$ 201,264
Income From Continuing Operations	$ 9,359	$ 12,330	$ 1,428	$ 3,048	$ 34,344
Net Income	$ 9,359	$ 12,330	$ 1,428	$ 3,048	$ 34,344
Earnings Per Common Share:					
Basic	$ .38	$ .47	$ .05	$ .10	$ .96
Diluted	$ .38	$ .46	$ .05	$ .10	$ .95
Total Assets	$ 147,734	$ 213,416	$ 233,096	$ 295,567	$ 346,288
Long-Term Debt	$ 42,255	$ 55,480	$ 75,048	$ 67,239	$ 54,000
Other Long-Term Liabilities	$ 2,360	$ 2,363	$ 2,368	$ 2,325	$ 3,597
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 1998, 1999 and 2000 activity.

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

Financial Condition and Liquidity

On March 20, 2000, we completed the acquisition, by merger, of Questa Oil and Gas Co.("Questa") under which Questa became a wholly owned subsidiary of Unit Corporation. In the merger, each of Questa's outstanding shares of common stock (excluding treasury shares) was converted into .95 shares of our common stock. We issued approximately 1.8 million shares as a result of this merger. The merger has been accounted for as a pooling of interests and, accordingly, all amounts within this document have been restated, unless otherwise noted, as if the companies had been combined during the periods presented.

Our bank loan agreement provides for a total loan facility of $100 million. Each year on April 1 and October 1 our banks redetermine our available borrowing value. This value is primarily determined by an amount equal to a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. An additional amount, limited to $20 million, is added to the borrowing value for a percentage of the value of a portion of our drilling rig fleet. Our loan agreement provides for a revolving credit facility which terminates on May 1, 2002 followed by a three year term loan. Borrowings under our loan agreement totaled $52 million at December 31, 2000 and $50 million at February 7, 2001. The latest borrowing value computation determined the full amount of the loan facility could be available to us, however, in order to reduce cost, we elected to set the borrowing value at $70 million for the current borrowing value period. We are charged a facility fee of .375 of 1 percent on any unused portion of the available borrowing value. The loan agreement also contains covenants which require us to maintain

- consolidated tangible net worth of at least $75 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 $18 million in any year.

The interest rate on our bank debt was 7.82 percent at December 31, 2000 and 6.72 percent at February 7, 2001. At our election, any portion of our outstanding bank debt may be fixed at the London Interbank Offered Rate ("Libor Rate"), as adjusted, depending on the level of our debt as a percentage of the available borrowing value. The Libor Rate may be fixed for periods of up to 30, 60, 90 or 180 days with the remainder of our bank debt being subject to the Chase Manhattan Bank, N. A. 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 $47.0 million at December 31, 2000 and $50.0 million at February 7, 2001.

Our shareholders' equity at December 31, 2000 was $214.5 million giving us a ratio of long-term debt-to-total capitalization of 20 percent. Our primary source of funds consists of the cash flow from our operations and borrowings under our bank loan agreement. Net cash provided by our operations in 2000 was $67.4 million compared to $24.7 million in 1999. We had working capital of $13.3 million at December 31, 2000. Our total 2000 capital expenditures were $65.3 million, of which $39.9 million was spent in our oil and natural gas operations. This segment's capital expenditures consisted primarily of $30.5 million for exploration and development drilling and $3.8 million for producing property acquisitions. Capital expenditures for our contract drilling operations totaled $22.0 and consisted primarily of $3.0 million to rebuild three of our drilling rigs, $3.2 million to acquire one rig and $1.5 million to start construction on two additional rigs. We also acquired $3.3 million in new drill pipe with the remainder of our drilling capital expenditures for major components for our rig fleet. We anticipate that we will spend approximately $20 million in 2001 for drilling rig equipment.

As natural gas and oil prices increased during the last six months of 1999 and throughout 2000, we increased the drilling activity in our exploration and production operation with the result that we drilled 101 wells during 2000 as compared to a total of 51 wells during the 1999. If oil and natural gas prices remain favorable, we plan to drill an estimated 130 wells and spend approximately $65 million drilling or buying oil and natural gas properties in 2001.

Most of our capital expenditures are discretionary and directed toward our future growth. Current operations do not depend on our ability to obtain funds outside of our loan agreement and our anticipated cash flow. Future decisions by us to acquire or drill on oil and natural gas properties will depend on prevailing or anticipated market conditions, potential return on investment, future drilling potential and the availability of opportunities to obtain financing under the circumstances involved, thus providing us with a large degree of flexibility in determining when and if to incur such costs.

On September 30, 1999, we completed the acquisition of 13 land drilling rigs from Parker Drilling Company and Parker Drilling Company North America, Inc., for 1,000,000 shares of our common stock and $40,000,000 in cash. The cash part of this acquisition was funded through a public offering of

7,000,000 shares of our common stock which closed on September 29, 1999. We received proceeds of $50.1 million from the offering net of commission fees and other costs.

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, 2000, promissory notes in the aggregate outstanding principal amount of $3.0 million. These notes are payable in equal annual installments on January 2, 2001 through January 2, 2003. The notes bear interest at the Chase Prime Rate which at December 31, 2000 was 9.5 percent and February 7, 2001 was 8.5 percent. At February 7, 2001, the promissory notes outstanding totaled $2.0 million.

Due to a settlement agreement which terminated at December 31, 1997, we have a liability of $877,000 at December 31, 2000, representing proceeds received from a natural gas purchaser as prepayment for natural gas. The $877,000 is payable in equal annual payments on June 1, 2001 and June 1, 2002.

The average price we received for our oil in 2000 increased 54 percent from the price we received in 1999 and our December 2000 oil price was 10 percent higher than the oil price we received in December 1999. Natural gas prices remain volatile, but increased substantially during the year. Our average natural gas price in 2000 was 91 percent higher than our average 1999 price and our December 2000 natural gas price was 239 percent higher than our December 1999 price. For the year, the average natural gas price we received was $3.91 per Mcf and the average oil price we received was $26.95 per barrel. Natural gas prices are influenced by weather conditions and supply imbalances, particularly in the domestic market, and by world wide oil price levels. Domestic oil price levels continue to be primarily influenced by world market developments. Since natural gas comprises approximately 90 percent of our total oil and natural gas reserves, natural gas prices have a significant effect on the value of our oil and natural gas reserves and large natural gas price declines could cause us to reduce the carrying value of our oil and natural gas properties. Any price decreases, if sustained, would also adversely affect our future cash flow by reducing our oil and natural gas revenues and, if continued over an extended period, could lessen not only the demand for our contract drilling rigs but also the rate we would receive. Any declines in natural gas and oil prices could also adversely affect the semi-annual determination of the loan value under our bank loan agreement since this determination is based on the value of our oil and natural gas reserves and our drilling rigs. Such a reduction would reduce the amount available to us under our loan agreement which, in turn, may affect our ability to carry out our capital projects.

Generally, during the past 17 years, our contract drilling operations have encountered significant competition, as reduced oil and natural gas prices during most of the period created a reduction in the demand for domestic land contract drilling rigs. However, in the last half of 1999 and throughout 2000 as oil and natural gas prices increased we experienced a substantial increase in demand for our rigs bringing our utilization rates above 90 percent for the last five months of 2000. Even with the increase in demand, we anticipate that competition within our industry will, for the foreseeable future, continue to influence the use of our drilling rigs. In addition to competition, our ability to use our drilling rigs at any given time depends on a number of other factors, including the continued strengthening of the price of both oil and natural gas, the availability of labor and our ability to supply the type of equipment required.

At December 31, 2000, we had tax net operating loss carryforwards ("NOL's") of approximately $39.5 million, the benefit of which has been recognized in our financial statements as we believe it to be more likely than not that we will use these NOL's. Should we be unable to generate sufficient income in future years to allow the use of all the NOL's, a charge to expense will be required to give recognition to any loss of the NOL's.

At December 31, 2000, one of our subsidiaries owned 4,949,500 shares of common stock and 1,800,000 warrants in Shenandoah Resources Ltd., which is a Canadian oil and natural gas exploration and production company. The investment of $2,426,000 is part of other assets in our consolidated balance sheet.

Effects of Inflation

In the previous 17 years the effects of inflation on our operations have been minimal due to low inflation rates and moderate demand for contract drilling services. In the last half of 1999 and throughout 2000, as drilling rig day rates and drilling rig utilization increased, the impact of inflation has increased as the availability of equipment and third party services have decreased. Due to industry wide demand for qualified labor, contract drilling labor cost increased substantially in the summer of 2000. How inflation will effect us in the future will depend on additional increases, if any, we realize in our drilling rig rates and the prices we receive for our oil and natural gas. If industry activity continues to increase, 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

On June 15, 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). The statement has subsequently been amended by FASB statements No. 137 and No. 138 and establishes new accounting and reporting standards for derivative instruments. We will be required to adopt this statement in the first quarter of 2001. This statement will require us to recognize all derivatives as either assets or liabilities on the balance sheet and measure the effectiveness of the hedges, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at fair value for each reporting period. The effective portion of the gain or loss on the derivative instrument will be recognized in other comprehensive income as a component of our equity until the hedged item is recognized in earnings. The ineffective portion of the derivative’s change in fair value is required to be recognized in earnings during the period the change in value occurs. We have evaluated all of our transactions that could potentially be classified as derivative instruments under FAS 133. The adoption of FAS 133 will not have a significant effect on our results of operations or financial position.

Results of Operations

2000 versus 1999

Net income for 2000 was $34,344,000, compared with $3,048,000 for 1999. This increase resulted primarily from increases in our natural gas and oil prices and production volumes. Higher oil and natural gas prices also elevated the demand for our drilling rigs, resulting in increased utilization of our rigs, dayrates and net income.

Our oil and natural gas revenues increased 99 percent in 2000 due to a 91 percent and 54 percent rise in the average prices we received for natural gas and oil, respectively. For the year, natural gas production increased by 11 percent and oil production increased by 15 percent when compared to 1999. Production grew as we drilled 101 gross wells (40.2 net wells) in 2000, compared to 51 gross wells (21.4 net wells) in 1999. Natural gas production for the fourth quarter of 2000 exceeded 1999's fourth quarter production by 11 percent.

In 2000, revenues from our contract drilling operations increased by 95 percent as the average number of our drilling rigs being used increased from 23.1 in 1999 to 39.8 in 2000. Revenues per rig per day increased 13 percent between the comparative years. The acquisition of the Parker drilling rigs added 6.5 rigs to our utilization rate in the fourth quarter of 1999 and 9.0 rigs to our 2000 utilization at dayrates substantially higher than those achieved in our other marketing area. Our rigs excluding those acquired from Parker added 9.3 rigs to utilization and added an additional 10 percent to their revenue per rig per day. Daywork revenues represented 75 percent of our total drilling revenues in 2000 and 61 percent in 1999.

Operating margins (revenues less operating costs) for our oil and natural gas operations were 79 percent in 2000 and 67 percent in 1999. This increase resulted primarily from the increase in the average oil and natural gas prices we received. Total operating costs between the comparative years increased 31 percent due primarily to the 113 percent increase in production taxes incurred as a result of higher revenues and to a lesser extent from the addition of new wells through development drilling.

Our contract drilling operating margins increased from 14 percent in 1999 to 22 percent in 2000. The additional operating margin was generally due to additional revenue received per day and an increase in the number of rigs utilized. Our contract drilling operating cost per rig per day increased $109 in 2000 as total contract drilling operating costs were up 76 percent in 2000 versus 1999 primarily due to increased utilization.

Contract drilling depreciation increased 75 percent due to the impact of higher depreciation per operating day associated with the newly acquired Parker rigs and an overall increase in our rig utilization. Depreciation, depletion and amortization ("DD&A") of our oil and natural gas properties increased 8 percent due to additional production volumes. The average DD&A rate per Mcfe decreased 4 percent to $0.82 in 2000.

General and administrative expenses increased 14 percent as certain employee costs, outside contract services and office expenses increased due to the growth in both of our operating segments. Interest expense decreased 3 percent as our average outstanding debt decreased 14 percent during 2000. The average interest rate increased from 7.0 percent in 1999 to 7.9 percent in 2000.

On May 3, 1999, our contract drilling offices in Moore, Oklahoma were struck by a tornado destroying two buildings and damaging various vehicles and drilling equipment. In May 1999, we received $500,000 of insurance proceeds for the destroyed buildings, and, as a result, in the second quarter of 1999, we recognized a gain of $315,000 recorded as part of other revenues. During the first quarter of 2000, we received the final insurance proceeds totaling $987,000 for the contents of the destroyed buildings, damaged equipment and clean up costs. From these proceeds, we recognized a gain of $599,000 recorded as part of other revenues in the first quarter of 2000.

1999 versus 1998

Net income for 1999 was $3,048,000, compared with $1,428,000 in 1998. Lower natural gas and oil prices in the first half of 1999 reduced both the demand for our drilling rigs and the rates we received for the drilling rigs that were operating. As a result of the merger with Questa, the oil and gas properties of Questa were restated from the successful efforts method of accounting to the full cost method of accounting used by Unit Corporation. As part of this restatement, in 1998, the value of Questa's oil and natural gas properties were impaired due to low prices at the end of the third quarter of 1998; therefore, the Questa properties were written down $2.6 million.

Our oil and natural gas revenues increased 7 percent in 1999 due to a 7 percent and 37 percent increase in the average prices we received for natural gas and oil, respectively. For the year, natural gas production decreased by 2 percent and oil production decreased by 13 percent when compared to 1998. Our oil production declined because we in recent years emphasized the drilling of development wells aimed at replacing and increasing our natural gas reserves. Our natural gas production decreased because we curtailed our development drilling program during the first half of 1999 while oil and natural gas prices were depressed. As prices began to improve during the last six months of 1999, our natural gas production increased as we increased our drilling program. Natural gas production for the fourth quarter of 1999 exceeded 1998's fourth quarter production by 4 percent.

In 1999, revenues from our contract drilling operations increased by 4 percent as the average number of drilling rigs being used increased from 22.9 in 1998 to 23.1 in 1999. Revenues per rig per day increased 3 percent between the comparative years. During the first nine months of 1999 as compared to the same period of 1998, our average drilling rig utilization was down 22 percent and our average revenues per rig per day was down 4 percent. The acquisition of the Parker drilling rigs added 6.5 rigs to our utilization rate in the fourth quarter of 1999 at dayrates substantially higher than those achieved in our other marketing area. As a result, that acquisition had a strong impact on our contract drilling fourth quarter and year-end operating results, adding $5.6 million in revenues. Daywork revenues represented 61 percent of our total drilling revenues in 1999 and 64 percent in 1998.

Operating margins (revenues less operating costs) for our oil and natural gas operations were 67 percent in 1999 and 64 percent in 1998. This increase resulted primarily from the increase in the average oil and natural gas prices we received and a 2 percent decrease in operating costs between the comparative years.

Our contract drilling operating margins decreased from 18 percent in 1998 to 14 percent in 1999. This reduction was generally due to decreases during the first nine months of 1999 in both daily drilling rig revenue rates and utilization and increases in operating costs. Total contract drilling operating costs were up 9 percent in 1999 versus 1998 due to increased labor costs and related benefit costs, including workers' compensation.

Contract drilling depreciation increased 19 percent due to the impact of higher depreciation per operating day associated with the newly acquired Parker rigs. Depreciation, depletion and amortization (“DD&A”) of our oil and natural gas properties decreased 13 percent. Total DD&A was higher in 1998 due to the write down of Questa’s oil and natural gas properties in the third quarter of 1998, as discussed above. Decreases in production as previously discussed also reduced DD&A in 1999. The average DD&A rate per Mcfe increased 5 percent to $0.85 in 1999.

General and administrative expenses increased 4 percent as certain employee benefit costs and outside services increased. Interest expense increased 6 percent as our average outstanding debt increased 11 percent during 1999. The average interest rate decreased from 7.1 percent in 1998 to 7.0 percent in 1999.

On May 3, 1999, our contract drilling offices in Moore, Oklahoma were struck by a tornado destroying two buildings and damaging various vehicles and drilling equipment. In May 1999, we received $500,000 of insurance proceeds for the destroyed buildings, and as a result, in the second quarter of 1999, we recognized a gain of $315,000 recorded as part of other revenues.

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 pricing of 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 have received for our oil and natural gas production have been volatile and such volatility is expected to continue.

To reduce the impact of price fluctuations, we periodically use hedging strategies to hedge the price we will receive for a portion of our future oil and natural gas production. In the first quarter of 2000, we entered into swap transactions in an effort to lock in a portion of our production at the higher oil prices which currently existed. These transactions applied to approximately 50 percent of our daily oil production covering the period from April 1, 2000 to July 31, 2000 and 25 percent of our daily oil production for August and September of 2000, at prices ranging from $24.42 to $27.01. We have also entered into a collar contract for approximately 25 percent of our daily production for the period covering November 1, 2000 to February 28, 2001. The collar has a floor of $26.00 and a ceiling of $33.00 and we are receiving $0.86 per barrel for entering into the collar transaction. During 2000, the sum of these hedging transactions yielded a reduction in our oil revenues of $465,000.

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 attempt to manage the exposure to increases in interest rates. However, we may consider the use of such financial instruments in the future based on our assessment of future interest rates. The impact on annual cash flow before taxes of a one percent change in the floating rate based on our average outstanding long-term debt in 2000 would have been approximately $628,000.

Item 8. *Financial Statements and Supplementary Data*

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	1999	2000
	Restated, See Note 2)	
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,647	$ 726
Accounts receivable (less allowance for doubtful accounts of $583 and $919)	22,070	40,220
Materials and supplies	3,259	3,802
Prepaid expenses and other	2,510	1,269
Total current assets	30,486	46,017
Property and Equipment:		
Drilling equipment	177,238	196,736
Oil and natural gas properties, on the full cost method	312,269	349,707
Transportation equipment	3,502	5,803
Other	7,694	8,801
	500,703	561,047
Less accumulated depreciation, depletion, amortization and impairment	241,649	270,690
Net property and equipment	259,054	290,357
Other Assets	6,027	9,914
Total Assets	$ 295,567	$ 346,288

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

	As of December 31,	
	1999	2000
	(Restated, See Note 2)	
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and other liabilities	$ 2,027	$ 1,627
Accounts payable	14,682	21,012
Accrued liabilities	8,517	9,854
Contract advances	358	179
Total current liabilities	25,584	32,672
Long-Term Debt	67,239	54,000
Other Long-Term Liabilities (Note 4)	2,325	3,597
Deferred Income Taxes	20,914	41,479
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	-	-
Common stock, $.20 par value, 40,000,000 and 75,000,000 shares authorized, 35,641,307 and 35,768,344 shares issued, respectively	7,128	7,154
Capital in excess of par value	139,207	139,872
Retained earnings	33,170	67,514
Total shareholders' equity	179,505	214,540
Total Liabilities and Shareholders' Equity	$ 295,567	$ 346,288

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	1998	1999	2000
	(Restated, See Note 2)	(Restated, See Note 2)	
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 53,528	$ 55,479	$ 108,075
Oil and natural gas	43,346	46,225	92,016
Other	400	648	1,173
Total revenues	97,274	102,352	201,264
Expenses:			
Contract drilling:			
Operating costs	43,729	47,721	84,051
Depreciation	5,766	6,851	11,999
Oil and natural gas:			
Operating costs	15,464	15,084	19,754
Depreciation, depletion, amortization and impairment	19,564	17,114	18,492
General and administrative	5,543	5,750	6,560
Interest	4,950	5,268	5,136
Total expenses	95,016	97,788	145,992
Income Before Income Taxes	2,258	4,564	55,272
Income Tax Expense:			
Current	214	29	621
Deferred	616	1,487	20,307
Total income taxes	830	1,516	20,928
Net Income	$ 1,428	$ 3,048	$ 34,344
Net Income Per Common Share:			
Basic	$ .05	$ .10	$ .96
Diluted	$ .05	$ .10	$ .95

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, 1998, 1999 and 2000
(1998 and 1999 Restated, See Note 2)

	Common Stock	Capital In Excess Of Par Value	Retained Earnings	Treasury Stock	Total
			(In thousands)		
Balances, January 1, 1998	$ 5,468	$ 81,837	$ 28,694	$ (156)	$ 115,843
Net income	-	-	1,428	-	1,428
Activity in employee compensation plans (48,329 shares)	10	144	-	156	310
Retirement of Shares	-	(58)	-	-	(58)
Purchase of treasury Stock (25,000 shares)	-	-	-	(131)	(131)
Questa purchase of treasury shares	-	(8)	-	-	(8)
Balances, December 31, 1998	5,478	81,915	30,122	(131)	117,384
Net income	-	-	3,048	-	3,048
Activity in employee compensation plans (252,511 shares)	50	680	-	131	861
Sale of Common Stock (7,000,000 shares)	1,400	48,682	-	-	50,082
Issuance of stock for acquisition (1,000,000 shares)	200	7,938	-	-	8,138
Questa purchase of treasury shares	-	(8)	-	-	(8)
Balances, December 31, 1999	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

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,		
	1998 (Restated, See Note 2)	1999 (Restated, See Note 2)	2000
		(In thousands)	
Cash Flows From Operating Activities:			
Net Income	$ 1,428	$ 3,048	$ 34,344
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization and impairment	25,681	24,285	30,946
Loss (gain) on disposition of assets	17	(400)	(969)
Employee stock compensation plans	561	436	443
Bad debt expense	-	255	350
Deferred tax expense	616	1,487	20,307
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	6,425	(8,450)	(18,500)
Materials and supplies	244	49	(543)
Prepaid expenses and other	(441)	140	(96)
Accounts payable	882	2,667	(1,370)
Accrued liabilities	60	1,590	3,067
Contract advances	205	48	(179)
Other liabilities	(447)	(442)	(440)
Net cash provided by operating activities	35,231	24,713	67,360

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,		
	1998	**1999**	**2000**
	(Restated, See Note 2)	**(Restated, See Note 2)**	
		(In thousands)	
Cash Flows From Investing Activities:			
Capital expenditures (including producing property acquisitions	$ (56,290)	$ (69,503)	$ (60,447)
Proceeds from disposition of property and equipment	964	1,438	4,259
(Acquisition) disposition of other assets	(93)	91	(2,656)
Net cash used in investing activities	(55,419)	(67,974)	(58,844)
Cash Flows From Financing Activities:			
Borrowings under line of credit	53,475	61,600	31,200
Payments under line of credit	(32,900)	(68,400)	(44,439)
Net payments on notes payable and other long-term debt	(495)	(1,090)	(556)
Proceeds from sale of common stock	(21)	50,136	250
Book overdrafts (Note 1)	-	2,974	3,108
Acquisition of treasury stock	(131)	-	-
Net cash provided by (used in) financing activities	19,928	45,220	(10,437)
Net Increase (Decrease) in Cash and Cash Equivalents	(260)	1,959	(1,921)
Cash and Cash Equivalents, Beginning of Year	948	688	2,647
Cash and Cash Equivalents, End of Year	$ 688	$ 2,647	$ 726
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest	$ 4,199	$ 5,850	$ 5,135
Income taxes	$ 617	$ 30	$ 519

See Note 2 for non-cash investing activities.

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statements include the accounts of Unit Corporation and its directly and indirectly wholly owned subsidiaries ("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 contact drilling and exploration and production activities are oriented toward drilling for and producing natural gas. At December 31, 2000, Unit had an interest in a total of 2,951 wells and served as operator of 667 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 2000, all of Unit's 47 rigs owned throughout the year 2000 were in operation. Unit acquired another rig at the end of the year and two more rigs were under construction, making the total rig count 50, at December 31, 2000.

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. 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, 1999 and 2000, book overdrafts of $3.0 million and $6.1 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 over the fair value of the net assets acquired and is being amortized on the straight-line method over 25 years. Goodwill is evaluated periodically for impairment, when it appears an impairment may have occurred. If an impairment is determined, the amount of such impairment is calculated based on the estimated fair market value of the related assets. Net goodwill reported in other assets at December 31, 1999 and 2000 was $5,575,000 and $5,331,000, respectively with accumulated amortization at December 31, 1999 and 2000 of $507,000 and $750,000, respectively.

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 $0.81, $0.85 and $0.82 per Mcfe in 1998, 1999 and 2000, 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 $11.0 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. As part of the merger with Questa, the oil and gas properties of Questa were restated from the successful effort method of accounting to the full cost method of accounting used by Unit Corporation. As part of this restatement, in 1998, the value of Questa's oil and natural gas properties were impaired due to low prices at the end of the third quarter of 1998; therefore, the properties were written down $2.6 million.

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 1998 and 2000, Unit recorded $437,000 and $179,000 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. No contract drilling profits were realized on such interests in 1999.

Limited Partnerships

Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in sixteen 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's wholly owned subsidiary, Questa Oil and Gas Co., is a general partner in two additional oil and natural gas limited partnerships sold privately. 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. Based upon the 2000 average natural gas price received of $3.91 per Mcf, Unit estimates its balancing position to be approximately $6.9 million on under-produced properties and approximately $6.0 million on over-produced properties. 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.

Employee and Director Stock Based Compensation

Unit applies APB Opinion 25 in accounting for its stock option plans for its employees and directors. 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 1998, 1999 and 2000 no compensation expense has been recognized. As provided by Financial Accounting Standard No. 123 "Accounting for Stock-Based Compensation," Unit has disclosed the pro forma effects of recording compensation for such option grants based on fair value in Note 6 to the financial statements.

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 $2,974,000 and $4,462,000 for employer group health insurance and worker's compensation at December 31, 1999 and 2000, respectively.

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 2000, one purchaser of Unit's oil and natural gas production accounted for approximately 12 percent of consolidated revenues. At December 31, 2000 accounts receivable from one oil and natural gas purchaser was approximately $12.5 million. In addition, at December 31, 1999 and 2000, Unit had a concentration of cash of $0.4 million and $1.7 million, respectively, with one bank.

Hedging Activities

To reduce the impact of fluctuations in the market prices of oil and natural gas, Unit periodically utilizes hedging strategies such as futures transactions or swaps to hedge the price of a portion of its future oil and natural gas production. Results of these hedging transactions are reflected in oil and natural gas sales in the month of the hedged production. At December 31, 1998 and 1999, Unit had no such hedging or derivative transactions. In the first quarter of 2000, we entered into swap transactions in an effort to lock in a portion of our daily production at the higher oil prices which currently existed. These transactions applied to approximately 50 percent of our 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. We have also entered into a collar contract for approximately 25 percent of our daily production for the period covering November 1, 2000 to February 28, 2001. The collar has a floor of $26.00 and a ceiling of $33.00 and we are receiving $0.86 per barrel for entering into the collar transaction. During 2000, the sum of these hedging transactions yielded a reduction in our oil revenues of $465,000.

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

On June 15, 1998, the Financial Accounting Standards Board (”FASB”) issued Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“FAS 133”). The statement has subsequently been amended by FASB statements No. 137 and No. 138 and establishes new accounting and reporting standards for derivative instruments. Unit will be required to adopt this statement in the first quarter of 2001. FASB 133 requires the recognition of all derivatives as either assets or liabilities on the balance sheet and measure the effectiveness of the hedges, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at fair value for each reporting period. The effective portion of the gain or loss on the derivative instrument will be recognized in other comprehensive income as a component of Unit’s equity until the hedged item is recognized in earnings. The ineffective portion of the derivative’s change in fair value is required to be recognized in earnings during the period the change in value occurs. Unit has evaluated all of the transactions that could potentially be classified as derivative instruments under FAS 133. The adoption of FAS 133 will not have a significant effect on the results of operations or financial position.

NOTE 2 - ACQUISITIONS AND MERGER

On March 20, 2000, Unit completed the acquisition, by merger, of Questa Oil and Gas Co.("Questa") under which Questa became a wholly owned subsidiary of Unit Corporation. In the merger each of Questa's outstanding shares of common stock (excluding treasury shares) was converted into .95 shares of our common stock. Unit issued approximately 1.8 million shares as a result of this merger. The merger has been accounted for as a pooling of interests and, accordingly, all amounts in the financial statements have been restated as if the companies had been combined throughout the periods presented.

The results of operations for each company and the combined amounts presented in Unit Corporation's consolidated financial statements are as follows:

	Year Ended December 31, 1998	Year Ended December 31, 1999	Three Months Ended March 31, 2000
		(In thousands)	
Revenues:			
Unit Corporation	$ 93,337	$ 97,453	$ 35,807
Questa	3,937	4,899	1,420
Combined	$ 97,274	$ 102,352	$ 37,227
Net Income:			
Unit Corporation	$ 2,246	$ 1,486	$ 3,095
Questa	(818)	1,562	483
Combined	$ 1,428	$ 3,048	$ 3,578

Questa's net income has been reduced by $1,219,000 in 1998, increased by $527,000 in 1999 and increased by $12,000 in the first quarter of 2000 to restate Questa's financial statements to the full cost method of accounting used by Unit.

On September 30, 1999, Unit acquired 13 land drilling rigs from Parker Drilling Company and Parker Drilling Company North America, Inc. Under the terms of the acquisition, the sellers received 1,000,000 shares of Unit's common stock valued at $8,138,000 and $40,000,000 in cash. The cash portion of the consideration was funded through an offering of 7,000,000 shares of Unit's common stock, which closed on September 29, 1999. The proceeds received by Unit from the offering were $50,082,000 net of commission fees and other costs. The acquisition has been accounted for as a purchase and the results of operations of the acquired rigs have been included in the consolidated financial statements since the date of acquisition.

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, 1998:			
Basic earnings per common share	$ 1,428,000	27,370,000	$ 0.05
Effect of dilutive stock options	-	340,000	
Diluted earnings per common share	$ 1,428,000	27,710,000	$ 0.05
For the Year Ended December 31, 1999:			
Basic earnings per common share	$ 3,048,000	29,639,000	$ 0.10
Effect of dilutive stock options	-	274,000	
Diluted earnings per common share	$ 3,048,000	29,913,000	$ 0.10
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

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,:

	1998	**1999**	**2000**
Options	191,000	196,500	144,000
Average exercise price	$ 8.60	$ 8.49	$ 16.59

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

Long-term debt consisted of the following as of December 31, 1999 and 2000:

	1999	**2000**
	(In thousands)	
Revolving credit and term loan, with interest at December 31, 1999 and 2000 of 7.5 percent and 7.8 percent, respectively	$ 62,400	$ 52,000
Notes payable for Hickman Drilling Company acquisition with interest at December 31, 1999 and 2000 of 8.5 percent and 9.5 percent, respectively	4,000	3,000
Notes payable to banks by Questa with interest at December 31, 1999 of 8.5 percent	2,147	-
	68,547	55,000
Less current portion	1,308	1,000
Total long-term debt	$ 67,239	$ 54,000

At December 31, 2000, Unit's bank loan agreement provided for a total loan commitment of $100 million consisting of a revolving credit facility through May 1, 2002 and a term loan thereafter, maturing on May 1, 2005. Borrowings under the loan agreement are limited to a borrowing value. At December 31, 2000, the latest borrowing value computation had determined the full amount of the loan facility could be available to Unit, but the company elected to set the borrowing value at $70 million in order to reduce cost. The loan value under the revolving credit facility is subject to a semi-annual re-determination calculated as the sum of a percentage of the discounted future value of Unit's oil and natural gas reserves, as determined by the banks. An additional amount, limited to $20 million, is added to the borrowing value from a percentage of the value of a portion of our drilling rig fleet. Any declines in commodity prices would adversely impact the determination of the borrowing 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 borrowing base. Subsequent to May 1, 2002, 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 paid an origination fee of $85,000 at inception of the loan agreement and a facility fee of 3/8 of one percent is charged for any unused portion of the borrowing value. 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 $75 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 $18 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, 1999, Questa had $2.1 million of notes payable to a local bank, collateralized by certain of Questa's oil and natural gas interests, bearing interest at the prime rate of 8.5 percent and payable in quarterly installments of $75,000 with all remaining principal and accrued interest due at maturity on June 30, 2001. Other 60 month notes payable of $22,000, collateralized by automotive equipment, were owed by Questa at December 31, 1999, at interest rates of 7.5 to 7.75 percent. All of Questa's long-term debt was paid before Questa merged with Unit.

Other long-term liabilities consisted of the following as of December 31, 1999 and 2000:

	1999	**2000**
	(In thousands)	
Natural gas purchaser prepayment	$ 1,317	$ 877
Separation benefit plan	1,419	1,811
Deferred compensation plan	-	1,536
Rig acquisition	248	-
Questa severance tax settlement payable	60	-
	3,044	4,224
Less current portion	719	627
Total other long-term liabilities	$ 2,325	$ 3,597

At December 31, 2000, Unit has a prepayment balance of $877,000 representing proceeds received from a purchaser for prepayment of natural gas under a natural gas settlement agreement, which terminated on December 31, 1997. This amount is net of natural gas recouped and net of certain amounts disbursed to other owners for their proportionate share of the prepayments. At termination, the December 31, 1997 prepayment balance of $2.2 million became payable in equal annual payments over a five year period. A payment of $441,000 is due on June 1, 2001 and the final payment of $436,000 is due on June 1, 2002.

Unit has other long-term liabilities of $3,347,000, consisting of $1,811,000 accrued in connection with its separation benefit plans and $1,536,000 accrued in connection with its Deferred Compensation Plan.

Estimated annual principal payments under the terms of long-term debt and other long-term liabilities from 2001 through 2005 are $1,627,000, $11,549,000, $18,333,000, $17,333,000 and $7,222,000. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2000 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:

	1998	1999	2000
	(In thousands)		
Income tax expense computed by applying the statutory rate	$ 768	$ 1,552	$ 19,345
State income tax, net of federal benefit	77	139	1,575
Goodwill and other	(15)	(175)	8
Income tax expense	$ 830	$ 1,516	$ 20,928

Deferred tax assets and liabilities are comprised of the following at December 31, 1999 and 2000:

	1999	2000
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 2,370	$ 3,308
Net operating loss carryforward	23,475	15,027
Statutory depletion carryforward	2,260	2,260
Investment tax credit carryforward	339	-
Alternative minimum tax credit carryforward	895	1,123
Gross deferred tax assets	29,339	21,718
Valuation allowance	(335)	-
Deferred tax liability- Depreciation, depletion and amortization	(49,918)	(63,197)
Net deferred tax liability	$ (20,914)	$ (41,479)

The deferred tax asset valuation allowance reflects that the investment tax credit carryforwards may not be utilized before the expiration dates due, in part, to the effects of anticipated future exploratory and development drilling costs. The reduction in the valuation allowance was the result of the expiration of investment tax credit carryforwards in 2000.

Realization of the deferred tax asset is dependent on generating sufficient taxable income prior to expiration of loss carryforwards. 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 during the carryforward period are reduced.

At December 31, 2000, Unit has net operating loss carryforwards for regular tax purposes of approximately $39,546,000 and net operating loss carryforwards for alternative minimum tax purposes of approximately $10,824,000, which expire in various amounts from 2001 to 2019. In addition, a statutory depletion carryforward of approximately $5,948,000, which may be carried forward indefinitely, is available to reduce future taxable income, subject to statutory limitations.

NOTE 6 - EMPLOYEE BENEFIT AND COMPENSATION PLANS

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan ("the Plan") whereby 330,950 shares of common stock were authorized for issuance under the Plan. 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. On January 4, 1999, 87,376 shares of common stock were issued for payment of Unit's 1998 year-end bonuses. No shares were issued under the Plan in 1998 and 2000.

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 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 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, 1998	574,160	$ 4.28
Granted	227,000	3.96
Exercised	(21,300)	2.71
Cancelled	(10,500)	7.05
Outstanding at December 31, 1998	769,360	4.19
Exercised	(109,760)	2.76
Cancelled	(2,000)	10.00
Outstanding at December 31, 1999	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

	OUTSTANDING OPTIONS		
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.37 - $ 4.00	439,100	4.8 years	$ 3.14
$ 7.25 - $16.69	280,600	8.1 years	$ 12.75

EXERCISE PRICES	EXERCISABLE OPTIONS NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
$ 2.37 - $ 4.00	313,400	$ 2.90
$ 7.25 - $10.00	94,500	$ 8.69

Options for 427,000, 414,200 and 407,900 shares were exercisable with weighted average exercise prices of $3.42, $3.96 and $4.24 at December 31, 1998, 1999 and 2000, 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 Director’s 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, 1998	60,000	$ 5.06
Granted	12,500	9.00
Outstanding at December 31, 1998	72,500	5.74
Granted	12,500	6.90
Exercised	(5,000)	5.13
Cancelled	(2,500)	8.94
Outstanding at December 31, 1999	77,500	5.86
Granted	17,500	12.19
Outstanding at December 31, 2000	95,000	$ 7.03

	OUTSTANDING AND EXERCISABLE OPTIONS		
EXERCISE PRICES	NUMBER OF SHARES	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE
$ 1.75 - $ 3.75	32,500	2.8 years	$ 3.00
$ 6.87 - $12.19	62,500	7.6 years	$ 9.12

Unit applies APB Opinion 25 in accounting for Unit's Stock Option Plan and Non-Employee Director's Stock Option Plan. Accordingly, based on the nature of Unit's grants of options, no compensation cost has been recognized in 1998, 1999 and 2000. 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:

	1998	1999	2000
Net Income (In thousands):			
As reported	$ 1,428	$ 3,048	$ 33,344
Pro forma	$ 1,115	$ 2,652	$ 33,986
Basic Earnings per Share:			
As reported	$ .05	$ .10	$ .96
Pro forma	$ .04	$ .09	$ .95
Diluted Earnings per Share:			
As reported	$ .05	$ .10	$ .95
Pro forma	$ .04	$ .09	$ .94

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility was 0.53, 0.55 and 0.55 in 1998, 1999 and 2000, respectively, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 4.95, 6.70 and 5.26 percent in 1998, 1999 and 2000, 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 1998 and 2000 under the Stock Option Plan were $527,000 and $1,470,000, respectively. No options were issued under the Stock Option Plan in 1999. Under the Non-Employee Director's Stock Option Plan the aggregate fair value of options granted during 1998, 1999 and 2000 were $71,000, $58,000 and $99,000, respectively.

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 46,892, 105,819 and 58,353 shares of common stock and recognized expense of $536,000, $464,000 and $595,000 in 1998, 1999 and 2000, 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, 1999 and 2000 totaled $1,165,000 and $1,536,000, 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 $577,000, $502,000 and $558,000 in 1998, 1999 and 2000, respectively, for benefits associated with anticipated payments from both separation plans.

NOTE 7 - TRANSACTIONS WITH RELATED PARTIES
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Unit formed private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2000, 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 its own account during the period from the formation of the Partnership 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 the three partnerships were dissolved.

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:

	1998	1999	2000
	(In thousands)		
Contract drilling	$ 180	$ 94	$ 296
Well supervision and other fees	$ 415	$ 425	$ 478
General and administrative expense reimbursement	$ 176	$ 175	$ 192

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, $21,000, $9,000 and $6,000 during the years ended December 31, 1998, 1999 and 2000, 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, 2005. Future minimum rental payments under the terms of the leases are approximately $478,000, $393,000, $386,000, $386,000 and $32,000 in 2001, 2002, 2003, 2004 and 2005, respectively. Total rent expense incurred by the Company was $412,000, $422,000 and $535,000 in 1998, 1999 and 2000, respectively.

Unit as a 40 percent owner in a corporation which provides gas gathering services, guarantees certain indebtedness of that corporation up to a maximum of $2 million (approximately $1,436,000 at December 31, 2000). The guarantee extends for a period ending on June 21, 2001.

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 $15,000, $10,000 and $14,000 in 1998, 1999 and 2000, respectively, for such limited partners' interests. Subsequent to the merger, 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.

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

In 1998, Unit adopted Statement of Financial Accounting Standard No. 131, "Disclosures about Segments of an Enterprise and Related 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.

	1998	1999	2000	
		(In thousands)		
Revenues:				
Contract drilling	$ 53,528	$ 55,479	$ 108,075	
Oil and natural gas	43,346	46,225	92,016	
Other	400	648	1,173	
Total revenues	$ 97,274	$ 102,352	$ 201,264	
Operating Income (1):				
Contract drilling	$ 4,033	$ 907	$ 12,025	
Oil and natural gas	8,318	14,027	53,770	
Total operating income	12,351	14,934	65,795	
General and administrative expense	(5,543)	(5,750)	(6,560)	
Interest expense	(4,950)	(5,268)	(5,136)	
Other income (expense)- net	400	648	1,173	
Income before income taxes	$ 2,258	$ 4,564	$ 55,272	
Identifiable Assets (2):				
Contract drilling	$ 69,147	$ 125,853	$ 141,324	
Oil and natural gas	160,424	164,252	198,251	
Total identifiable assets	229,571	290,105	339,575	
Corporate assets	3,525	5,462	6,713	(3)
Total assets	$ 233,096	$ 295,567	$ 346,288	

	1998	1999	2000
	(In thousands)		
Capital Expenditures:			
Contract drilling	$ 11,485	$ 55,656	$ 22,045
Oil and natural gas	41,046	21,532	39,884
Other	216	744	3,324
Total capital expenditures	$ 52,747	$ 77,932	$ 65,253
Depreciation, Depletion, Amortization and Impairment:			
Contract drilling	$ 5,766	$ 6,851	$ 11,999
Oil and natural gas	19,564	17,114	18,492
Other	351	320	455
Total depreciation, depletion, amortization and impairment	$ 25,681	$ 24,285	$ 30,946

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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 an investment in a Canadian oil and natural gas exploration and production company of $2,426,000.

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 1999 and 2000 is as follows:

	Three Months Ended			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
Year ended	(In thousands except per share amounts)			
December 31, 1999:				
Revenues	$ 20,626	$ 20,495	$ 23,920	$ 37,311
Gross profit(1)	$ 851	$ 1,272	$ 4,551	$ 8,260
Income (loss) before income taxes	$ (1,760)	$ (1,047)	$ 1,870	$ 5,501
Net income (loss)	$ (1,119)	$ (656)	$ 1,094	$ 3,729
Earnings (loss) per common share:				
Basic (2)	$ (0.04)	$ (0.02)	$ 0.04	$ 0.10
Diluted (3)	$ (0.04)	$ (0.02)	$ 0.04	$ 0.10
December 31, 2000:				
Revenues	$ 37,227	$ 43,587	$ 54,788	$ 65,662
Gross profit(1)	$ 7,719	$ 11,810	$ 18,154	$ 28,112
Income before Income taxes	$ 5,648	$ 9,076	$ 15,622	$ 24,926
Net income	$ 3,578	$ 5,627	$ 9,685	$ 15,454
Earnings per Common share:				
Basic	$ 0.10	$ 0.16	$ 0.27	$ 0.43
Diluted (4)	$ 0.10	$ 0.16	$ 0.27	$ 0.43

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

(2) As a result of shares issued during the year, earnings per share for the year’s four quarters, which is based on average shares outstanding during each quarter, does not equal the annual earnings per share, which is based on the average shares outstanding during the year.

(3) Due to the effect of additional shares sold in the equity offering and issued for the Parker rig acquisition and 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.

(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)	
1998:			
Capitalized costs:			
Proved properties	$ 279,988	$ 480	$ 280,468
Unproved properties	10,602	281	10,883
	290,590	761	291,351
Accumulated depreciation, depletion, amortization and impairment	(141,287)	(412)	(141,699)
Net capitalized costs	$ 149,303	$ 349	$ 149,652
Cost incurred:			
Unproved properties	$ 4,856	$ 203	$ 5,059
Producing properties	9,223	-	9,223
Exploration	2,380	-	2,380
Development	24,384	-	24,384
Total costs incurred	$ 40,843	$ 203	$ 41,046
1999:			
Capitalized costs:			
Proved properties	$ 301,725	$ 508	$ 302,233
Unproved properties	9,654	382	10,036
	311,379	890	312,269
Accumulated depreciation, depletion, amortization and impairment	(158,147)	(420)	(158,567)
Net capitalized costs	$ 153,232	$ 470	153,702
Cost incurred:			
Unproved properties	$ 1,724	$ 101	$ 1,825
Producing properties	3,733	28	3,761
Exploration	2,037	-	2,037
Development	13,909	-	13,909
Total costs incurred	$ 21,403	$ 129	$ 21,532

	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	$ 5,522	$ 16	$ 5,538
Producing properties	3,752	45	3,797
Exploration	2,409	-	2,409
Development	28,140	-	28,140
Total costs incurred	$ 39,823	$ 61	$ 39,884

The results of operations for producing activities are provided below.

	USA	CANADA	TOTAL
		(In thousands)	
1998:			
Revenues	$ 40,133	$ 55	$ 40,188
Production costs	(12,684)	(20)	(12,704)
Depreciation, depletion amortization and impairment	(19,384)	(8)	(19,392)
	8,065	27	8,092
Income tax expense	(3,094)	(9)	(3,103)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 4,971	$ 18	$ 4,989
1999:			
Revenues	$ 42,999	$ 63	$ 43,062
Production costs	(11,739)	(20)	(11,759)
Depreciation, depletion and amortization	(16,848)	(8)	(16,856)
	14,412	35	14,447
Income tax expense	(4,387)	(14)	(4,401)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 10,025	$ 21	$ 10,046
2000:			
Revenues	$ 88,461	$ 110	$ 88,571
Production costs	(16,457)	(19)	(16,476)
Depreciation, depletion and amortization	(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

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)			
1998:						
Proved developed and undeveloped reserves:						
Beginning of year	4,596	159,012	-	723	4,596	159,735
Revision of previous estimates	(1,205)	(5,484)	-	(162)	(1,205)	(5,646)
Extensions, discoveries and other additions	466	33,413	-	-	466	33,413
Purchases of minerals in place	261	7,169	-	-	261	7,169
Sales of minerals in place	(3)	(532)	-	-	(3)	(532)
Production	(486)	(17,694)	-	(38)	(486)	(17,732)
End of Year	3,629	175,884	-	523	3,629	176,407
Proved developed reserves:						
Beginning of year	3,871	129,422	-	295	3,871	129,717
End of year	2,749	134,504	-	421	2,749	134,925
1999:						
Proved developed and undeveloped reserves:						
Beginning of year	3,629	175,884	-	523	3,629	176,407
Revision of previous estimates	1,046	1,308	-	81	1,046	1,389
Extensions, discoveries and other additions	157	19,398	-	-	157	19,398
Purchases of minerals in place	139	7,922	-	-	139	7,922
Sales of minerals in place	(20)	(340)	-	-	(20)	(340)
Production	(424)	(17,402)	-	(35)	(424)	(17,437)
End of Year	4,527	186,770	-	569	4,527	187,339
Proved developed reserves:						
Beginning of year	2,749	134,504	-	421	2,749	134,925
End of year	3,583	144,992	-	467	3,583	145,459

	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

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 our reserves as prepared by our 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)	
1998:			
Future cash flows	$ 418,744	$ 1,089	$ 419,833
Future production and development costs	(167,114)	(271)	(167,385)
Future income tax expenses	(51,702)	(160)	(51,862)
Future net cash flows	199,928	658	200,586
10% annual discount for estimated timing of cash flows	(68,705)	(259)	(68,964)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 131,223	$ 399	$ 131,622
1999:			
Future cash flows	$ 557,915	$ 1,281	$ 559,196
Future production and development costs	(213,929)	(344)	(214,273)
Future income tax expenses	(81,039)	(175)	(81,214)
Future net cash flows	262,947	762	263,709
10% annual discount for estimated timing of cash flows	(95,722)	(285)	(96,007)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 167,225	$ 477	$ 167,702
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

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

	USA	CANADA	TOTAL
		(In thousands)	
1998:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (27,449)	$ (35)	$ (27,484)
Net changes in prices and production costs	(46,042)	(186)	(46,228)
Revisions in quantity estimates and changes in production timing	(18,105)	(335)	(18,440)
Extensions, discoveries and improved recovery, less related costs	28,096	-	28,096
Purchases of minerals in place	6,711	-	6,711
Sales of minerals in place	(603)	-	(603)
Accretion of discount	19,741	91	19,832
Net change in income taxes	18,352	486	18,838
Other - net	1,087	(13)	1,074
Net change	(18,212)	8	(18,204)
Beginning of year	149,435	391	149,826
End of year	$ 131,223	$ 399	$ 131,622
1999:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (31,260)	$ (44)	$ (31,304)
Net changes in prices and production costs	42,319	23	42,342
Revisions in quantity estimates and changes in production timing	987	44	1,031
Extensions, discoveries and improved recovery, less related costs	24,035	-	24,035
Purchases of minerals in place	8,612	-	8,612
Sales of minerals in place	(320)	-	(320)
Accretion of discount	8,096	44	8,140
Net change in income taxes	(18,355)	7	(18,348)
Other - net	1,888	4	1,892
Net change	36,002	78	36,080
Beginning of year	131,223	399	131,622
End of year	$ 167,225	$ 477	$ 167,702

	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

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 ($25.55) and natural gas ($9.41) 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. This year-end spot natural gas price was significantly higher than the average natural gas price of $6.89 received by Unit in December 2000 and the natural gas price that Unit expects to receive in the future.

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, 1999 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, 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 7, 2001

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 executive officer of Unit. 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
King P. Kirchner	73	Chairman of the Board, Chief Executive Officer and Director
John G. Nikkel	66	President, Chief Operating Officer and Director
Earle Lamborn	66	Senior Vice President, Drilling and Director
Philip M. Keeley	59	Senior Vice President, Exploration and Production
Larry D. Pinkston	46	Vice President, Treasurer and Chief Financial Officer
Mark E. Schell	43	General Counsel and Secretary

Mr. Kirchner, a co-founder of Unit, has been the Chairman of the Board and a director since 1963 and was President until November 1983. Mr. Kirchner is a Registered Professional Engineer within the State of Oklahoma, having received degrees in Mechanical Engineering from Oklahoma State University and in Petroleum Engineering, with honors, from the University of Oklahoma. Following graduation, he was employed by, Lufkin Manufacturing as a development engineer for hydraulic pumping units. Prior to co-founding Unit, he served in the US Army during the Korean War and after that as vice-president - engineering and operations for Woolaroc Oil Company.

Mr. Nikkel joined Unit in 1983 as its President and a director. 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 that Company 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. 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 49 years, joining Unit's predecessor in 1952 prior to it becoming a publicly-held corporation. He was elected Vice President, Drilling in 1973 and to his current position as Senior Vice President and director in 1979.

Mr. Keeley joined Unit in November 1983 as a Senior Vice President, Exploration and Production. Prior to that time, Mr. Keeley co-founded (with Mr. Nikkel) Nike Exploration Company in January 1982 and serves 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 as 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. 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 of 1987, as its Secretary and General Counsel. 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 2001 annual meeting of stockholders.

Item 11. *Executive Compensation*

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 2001 annual meeting of stockholders.

Item 12. *Security Ownership of Certain Beneficial Owners and Management*

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 2001 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 2001 annual meeting of stockholders.

PART IV

Item 14. *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, 1999 and 2000
Consolidated Statements of Operations for the years ended December 31, 1998, 1999 and 2000
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 1998, 1999 and 2000
Consolidated Statements of Cash Flows for the years ended December 31, 1998, 1999 and 2000
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, 1998, 1999 and 2000:

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:

10.2.38 Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herewith).

10.2.39* Form of Unit Corporation Key Employee Change of Control Contract (filed herewith).

21 Subsidiaries of the Registrant (filed herewith).

23 Consent of Independent Accountants (filed herewith).

* 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:

No reports on Form 8-K were filed during the quarter ended December 31, 2000.

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, 1998	$ 514	$ -	$ 80	$ 434
Year ended December 31, 1999	$ 434	$ 305	$ 15	$ 583
Year ended December 31, 2000	$ 583	$ 350	$ 14	$ 919

Deferred Tax Asset Valuation Allowance:

Description	Balance at Beginning of period	Additions	Deductions	Balance at End of period
		(In thousands)		
Year ended December 31, 1998	$ 1,552	$ -	$ 1,022	$ 530
Year ended December 31, 1999	$ 530	$ -	$ 195	$ 335
Year ended December 31, 2000	$ 335	$ -	$ 335	$ -

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 20, 2001 By: /s/ John G. Nikkel

JOHN G. NIKKEL
President and Chief Operating 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 20th day of March, 2001.

Name	Title
/s/ King P. Kirchner **KING P. KIRCHNER**	Chairman of the Board and Chief Executive Officer, Director
/s/ John G. Nikkel **JOHN G. NIKKEL**	President and Chief Operating Officer, Director
/s/ Earle Lamborn **EARLE LAMBORN**	Senior Vice President, Drilling, Director
/s/ Larry D. Pinkston **LARRY D. PINKSTON**	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