SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **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, 2004

OR

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

For the transition period from to

[Commission File Number 1-9260]

UNIT CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Delaware	**73-1283193**
(State of Incorporation)	**(I.R.S. Employer Identification No.)**
7130 South Lewis, Suite 1000 **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 ☒ No ☐

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

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

Yes ☒ No ☐

Aggregate Market Value of the Voting Stock Held By
Non-affiliates on June 30, 2004 – $1,262,168,792

Number of Shares of Common Stock
Outstanding on March 7, 2005 – 45,838,644

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 4, 2005, to be filed subsequently—Part III.

Exhibit Index - See Page 83

FORM 10-K
UNIT CORPORATION

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2004

PART I

Our executive offices are at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700. In addition to our executive offices, we have offices in Houston, Humble, Borger, Booker and Midland, Texas; Casper, Wyoming; Oklahoma City and Woodward, Oklahoma; and Denver, Colorado.

The following table provides certain information regarding us as of March 1, 2005:

• Number of drilling rigs we own	103
• Number of wells in which we own an interest	5,910
• Number of natural gas gathering systems we own	32
• States in which our principal operations are located	Oklahoma, Texas, Wyoming, Louisiana and New Mexico

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

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

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

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

OUR BUSINESS

We were founded in 1963 as a contract drilling company. Today, through our three principal wholly owned subsidiaries, Unit Drilling Company, Unit Petroleum Company and Superior Pipeline Company, L.L.C., we

- contract to drill onshore oil and natural gas wells for our own account and for others,
- explore, develop, acquire and produce oil and natural gas properties for our own account, and
- purchase, gather, process and treat natural gas for our own account and for third parties.

At various times, and from time to time, each of these three principal subsidiaries may conduct their operations through subsidiaries of their own.

OUR LAND CONTRACT DRILLING BUSINESS

General. Our wholly owned subsidiary, Unit Drilling Company, drills onshore natural gas and oil wells for our own account as well as for a wide range of other oil and gas companies. Its operations are mainly located in the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and in the East Texas and Rocky Mountain regions.

The table below identifies certain information concerning our contract drilling operations:

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Number of Rigs Owned at End of Period	100.0	88.0	75.0	55.0	50.0
Average Number of Rigs Owned During Period	93.0	75.9	61.6	51.8	47.0
Average Number of Rigs Utilized	88.1	62.9	39.1	46.3	39.8
Utilization Rate (1)	95%	83%	63%	90%	85%
Average Revenue Per Day (2)	$9,247	$7,972	$8,285	$9,879	$7,432
Total Footage Drilled (Feet in 1000's)	9,261	6,580	3,829	4,008	3,650
Number of Wells Drilled	832	530	318	361	316

(1) Utilization rate is determined by dividing the number of drilling rigs used by the average number of rigs owned during period.

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

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

Our drilling rigs have maximum depth capacities ranging from 5,000 to 40,000 feet.

The following table shows the distribution of our drilling rigs as of March 1, 2005:

Region	Contracted Rigs	Idle Rigs	Total Rigs	Average Rated Drilling Depths (ft)
Anadarko Basin Oklahoma	63	—	63	17,000
Arkoma Basin	7	—	7	13,000
East Texas and Gulf Coast	13	—	13	18,000
Rocky Mountains	20	—	20	16,000

At present, we do not have a shortage of drilling rig related equipment. However, at any given time, our ability to use all of our drilling rigs is dependent on a number of conditions, including the availability of qualified labor, drilling supplies and equipment as well as demand. As demand for our drilling rigs improved through 2004, it became increasingly difficult to find additional qualified labor to work on our drilling rigs. If demand for our drilling rigs remains at its current level or increases, we expect competition for qualified labor to continue which will result in higher operating costs.

Acquisitions. On July 30, 2004, we completed our acquisition of Sauer Drilling Company, a Casper, Wyoming-based drilling company. We paid $40.3 million in this acquisition which included $5.3 million for working capital. This acquisition included nine drilling rigs, a fleet of trucks, and an equipment and repair yard with associated inventory located in Casper, Wyoming. The drilling rigs range from 500 horsepower to 1,000 horsepower with depth capacities rated from 5,000 feet to 16,000 feet. The fleet of trucks consists of four vacuum trucks, and 11 rig-up trucks which are used to move the drilling rigs to new locations. We also use the trucks to move other drilling contractors' drilling rigs. This acquisition increased our share of the drilling rig market in the

Rocky Mountains in the medium-to-smaller drilling rig depth ranges. The equipment yard will continue to provide service space for the nine newly acquired drilling rigs and trucks as well as for our other drilling rigs located in our Rocky Mountain Division.

On May 4, 2004, we acquired two drilling rigs and related equipment for $5.5 million. These drilling rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. We refurbished the drilling rigs for approximately $4.0 million. One drilling rig was placed into service at the beginning of August 2004 and the other drilling rig was placed into service in the middle of September 2004. Both of these drilling rigs are working in our Rocky Mountain Division.

With these two acquisitions and the completion of construction of another 1,500 horsepower diesel electric drilling rig in June 2004, our total drilling rig fleet at December 31, 2004 was 100 drilling rigs.

On January 5, 2005, we acquired a subsidiary of Strata Drilling L.L.C. for $10.5 million. In this acquisition we acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major drilling rig components. These two drilling rigs are both 1,500 horsepower, diesel electric drilling rigs with the capacity to drill 12,000 to 20,000 feet. One drilling rig is currently operating and the other will require approximately $2.0 million in expenditures to complete. This latter drilling rig should be fully operational within 90 days. Both of these drilling rigs will ultimately be moved into our Rocky Mountain Division.

Also in January 2005, we completed the construction of a 1,500 horsepower diesel electric drilling rig which began operating in the Anadarko Basin. The addition of this drilling rig, when combined with the two we obtained in our acquisition from Strata Drilling L.L.C., brings our total drilling rig fleet to 103 drilling rigs as of March 1, 2005.

We plan to initiate construction of our 104th drilling rig in the first quarter of 2005. This drilling rig will be a 1,500 horsepower diesel electric drilling rig and is scheduled to be added to our Rocky Mountain Division.

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

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

Under turnkey contracts we may incur losses if we underestimate the costs to drill the well or if unforeseen events occur. To date, we have not experienced significant losses in performing turnkey contracts. In 2004, we did not drill any turnkey wells while in 2003 we drilled six turnkey wells, and turnkey revenue represented 1% of our 2003 contract drilling revenues. Because market conditions as well as the desires of our customers determine the use of turnkey contracts, we can’t predict whether the portion of drilling conducted on a turnkey basis will increase in the future.

Customers. During 2004, 10 customers accounted for approximately 44% of our contract drilling revenues. Chesapeake Operating, Inc. was our largest customer providing 11% of our total contract drilling revenues. Thirty-five of the wells we drilled in 2004 were operated by our exploration and production subsidiary. These latter wells also have working interests which are owned by limited partnerships for which we act as general partner. As required by the SEC, the profit received by our contract drilling subsidiary when we drill wells for our exploration and production subsidiary, which amounted to $3.7 million and $1.9 million during 2004 and 2003, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Additional Information. Further information relating to our contract drilling operations can be found in Notes 1, 2, 10 and 12 of the Notes to Consolidated Financial Statements in Item 8 of this report.

OUR OIL AND NATURAL GAS BUSINESS

General. In 1979 we began to develop our exploration and production operations to diversify our contract drilling revenues. Today, our wholly owned subsidiary, Unit Petroleum Company, conducts our exploration and production activities. Until it was merged into Unit Petroleum Company on March 3, 2005, we also conducted operations through our subsidiary PetroCorp Incorporated. Our producing oil and natural gas properties, undeveloped leaseholds and related assets are mainly in Oklahoma, Texas, Louisiana and New Mexico and, to a lesser extent, in Arkansas, North Dakota, Colorado, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan and Canada.

The following table presents certain information regarding our oil and gas operations as of December 31, 2004:

Property/Area	Number of Gross Wells	Number of Net Wells	2004 Average Daily Production Mcf	2004 Average Daily Production Bbls
Western Division (includes the Rocky Mountain Region, New Mexico, Western and Southern Texas and the Gulf Coast Region)	2,761	367.45	26,650	1,811
East Division (consists principally of the Appalachian Region, Arkansas, East Texas and Eastern Oklahoma)	651	148.07	19,332	54
Central Division (consist principally of Kansas, Western Oklahoma and Texas Panhandle Area)	2,406	573.61	27,817	999
Canada	67	2.03	380	—
Total	5,885	1,091.16	74,179	2,864

When we are the operator of a property, we generally use drilling rigs owned by our subsidiary Unit Drilling Company.

Acquisition. On January 30, 2004, we acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash. PetroCorp explored and developed oil and natural gas properties primarily in Texas and Oklahoma. Approximately 84% of the oil and natural gas properties acquired in this acquisition are located in the Mid-Continent and Permian basins, while 6% are located in the Rocky Mountains and 10% are located in the Gulf Coast Basin. The acquired properties increased our oil and natural gas reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide additional locations for our future development drilling.

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

	Year Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploratory:						
Oil	1	.05	—	—	—	—
Natural gas	5	1.42	3	1.84	2	0.50
Dry	1	.31	1	1.00	5	2.00
	7	1.78	4	2.84	7	2.50
Development:						
Oil	17	5.71	5	2.13	4	1.91
Natural gas	121	48.60	120	46.22	68	33.25
Dry	23	13.40	20	10.38	17	14.21
	161	67.71	145	58.73	89	49.37
Total	168	69.49	149	61.57	96	51.87
Oil and Natural Gas Wells Producing or Capable of Producing:						
Oil—USA	2,715	418.51	803	280.40	790	273.34
Oil—Canada	1	.03	—	—	—	—
Gas—USA	3,103	670.62	2,525	547.99	2,449	524.45
Gas—Canada	66	2.00	65	1.63	65	1.63
Total	5,885	1,091.16	3,393	830.02	3,304	799.42

As of March 1, 2005, we have participated in the drilling of 25 gross (7.3 net) wells during 2005.

Cost incurred for development drilling includes $16.0 million, $20.4 million and $10.8 million in 2004, 2003 and 2002, respectively, to develop booked proved undeveloped oil and natural gas reserves.

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

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
2004 (1):				
USA	746,153	218,062	251,138	121,973
Canada	39,040	976	6,400	2,413
Total	785,193	219,038	257,538	124,386
2003:				
USA	600,872	173,674	159,663	90,862
Canada	39,040	976	4,162	2,624
Total	639,912	174,650	163,825	93,486
2002:				
USA	585,313	166,397	142,764	79,911
Canada	39,040	976	5,441	3,360
Total	624,353	167,373	148,205	83,271

(1) Approximately 85% of the net undeveloped acres are covered by leases that will expire in each of the years 2005 – 2007 unless drilling or production otherwise extends the terms of the leases.

The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2005, 2006 and 2007, as disclosed in our December 31, 2004 oil and natural gas reserve report are $42.5 million, $31.3 million and $7.9 million, respectively. No future development costs have been estimated for Canada.

Price and Production Data. The following table identifies the 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] for our oil and natural gas production for the years indicated:

	Year Ended December 31,		
	2004	**2003**	**2002**
Average Sales Price per Barrel of Oil Produced:			
USA price before hedging	$ 36.63	$ 26.95	$ 21.54
Effect of hedging	(3.43)	(0.01)	—
USA price including hedging	$ 33.20	$ 26.94	$ 21.54
Canada	$ —	$ —	$ —
Average Sales Price per Mcf of Natural Gas Produced:			
USA price before hedging	$ 5.43	$ 4.87	$ 2.87
Effect of hedging	—	—	—
USA price including hedging	$ 5.43	$ 4.87	$ 2.87
Canada price before hedging (U.S. Dollars)	$ 4.91	$ 4.49	$ 2.11
Effect of hedging (U.S. Dollars)	—	—	—
Canada price including hedging (U.S. Dollars)	$ 4.91	$ 4.49	$ 2.11
Oil Production (Mbbls):			
USA	1,048	516	473
Canada	—	—	—
Total	1,048	516	473
Natural Gas Production (MMcf):			
USA	27,010	20,610	18,927
Canada	139	38	41
Total	27,149	20,648	18,968
Average Production Cost per Equivalent Mcf:			
USA	$ 1.08	$ 0.90	$ 0.79
Canada	$ 0.42	$ 0.56	$ 0.60

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

	Year Ended December 31,		
	2004	**2003**	**2002**
Oil (Mbbls):			
USA	8,561	5,141	4,096
Canada	—	—	—
Total	8,561	5,141	4,096
Natural gas (MMcf):			
USA	295,146	253,542	244,494
Canada	260	650	317
Total	295,406	254,192	244,811

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

Additional Information. Further information relating to our oil and natural gas operations can be found in Notes 1, 2, 10 and Supplemental Information of the Notes to Consolidated Financial Statements in Item 8 of this report.

OUR NATURAL GAS GATHERING AND PROCESSING BUSINESS

General. In July 2004, we consolidated and increased our natural gas gathering and processing business when we acquired the 60% of Superior Pipeline Company L.L.C. that we did not already own. We paid $19.8 million in this acquisition. Before July 2004, we owned 18 gathering systems which we have now consolidated with Superior's systems. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas and operates one natural gas treatment plant, owns three processing plants, 32 active gathering systems and 440 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana. It has been in business since 1996. This acquisition and consolidation will increase our ability to gather and market our natural gas (as well as third party natural gas) and construct or acquire existing natural gas gathering and processing facilities. Before this acquisition, our 40% interest in the income or loss from operations of Superior was shown as equity in earnings of unconsolidated investments.

The following table presents certain information regarding our natural gas gathering and processing operations:

	Year Ended December 31,		
	2004	2003	2002
Gas Gathered—MMBtu/day	33,147	16,413	9,474
Gas Processed—MMBtu/day	13,412	92	94

Additional Information. Further information relating to our natural gas gathering and processing operations can be found in Notes 1, 2 and 10 of the Notes to Consolidated Financial Statements in Item 8 of this report.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for natural gas and oil significantly affect our revenues, operating results, cash flow and future rate of growth. Because natural gas makes up the biggest part of our oil and natural gas reserves, as well as the focus of most of the contract drilling work we do for others, changes in natural gas prices have a larger impact on us than changes in oil prices. Historically, oil and natural gas prices have been volatile, and we expect them to continue to be so. The following table shows the highest and lowest average monthly natural gas and oil price we received, by quarter, for each of the periods indicated:

	Average Monthly Natural Gas Price per Mcf		Average Monthly Oil Price per Bbl	
QUARTER	High	Low	High	Low
2004:				
First	$5.48	$4.52	$31.51	$28.19
Second	$6.15	$5.24	$31.84	$30.34
Third	$5.88	$4.42	$37.50	$31.14
Fourth	$6.65	$5.20	$38.69	$32.44
2003:				
First	$8.38	$4.18	$32.72	$27.74
Second	$5.59	$4.22	$27.10	$24.56
Third	$4.63	$4.36	$27.41	$23.62
Fourth	$5.06	$4.06	$27.48	$26.31

QUARTER	Average Monthly Natural Gas Price per Mcf		Average Monthly Oil Price per Bbl	
	High	Low	High	Low
2002:				
First	$2.11	$1.87	$19.60	$15.58
Second	$3.03	$2.98	$23.44	$22.07
Third	$2.97	$2.47	$23.57	$23.01
Fourth	$3.95	$3.35	$25.59	$21.90

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 and Venezuela;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- demand for oil and natural gas from other developing nations including China and India;
- the price of foreign imports;
- actions of governmental authorities;
- the domestic and foreign supply of oil and natural gas;
- the level of consumer demand;
- United States storage levels of natural gas;
- the ability to transport to key markets;
- 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 the future prices of oil and natural gas.

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. We started to experience less demand for our drilling rigs starting in October, 2001 as natural gas prices began to fall in early 2001. The rates received for our drilling rigs also began to fall until they reached a low of $7,275 per day in February of 2003. As natural gas and oil prices once again began to rise during the second quarter of 2003 and have remained at higher levels throughout 2004, both demand for our drilling rigs and dayrates have steadily increased. In December 2004, the average dayrate of the 100 drilling rigs that we owned was $9,786 per day. Since short-term and long-term trends in oil and natural gas prices affect the demand for our drilling rigs, future demand and dayrates received for our drilling services is uncertain.

Our natural gas gathering and processing operations provide us greater flexibility in delivering our (and other parties) natural gas from the wellhead to major natural gas pipelines. Margins received for the delivery of this natural gas is dependent on the price for natural gas and the demand for natural gas in our area of operations. If the price of natural gas liquids falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to extract certain natural gas liquids. The volumes of natural gas processed is highly dependent on the volume and Btu content of the natural gas gathered.

COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in onshore contract drilling traditionally involves factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our onshore contract drilling competitors are substantially larger than we are and have greater financial and other resources than we do.

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

Our natural gas gathering and processing operations compete with purchasers and gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, as well as independent gatherers for the right to purchase natural gas, build gathering systems in production fields and deliver the natural gas once the gathering systems are established. The principal elements of competition include the rates, terms of services, reputation and the flexibility and reliability of service.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 11 oil and gas limited partnerships. Four of these partnerships were formed for investment by third parties and seven (the employee partnerships) were formed to allow our employees and directors to participate with Unit Petroleum Company in its operations. The partnerships formed for use in connection with third party investments were formed in 1984, 1985 and 1986. One employee partnership has been formed each year beginning with 1984.

The employee partnerships formed in 1984 through 1990 were consolidated into a single consolidating partnership in 1993 and the employee partnerships formed in 1991 through 1999 were also consolidated into the consolidating partnership in 2002. The consolidation of the 1991 through the 1999 employee partnerships was done by the general partner under the terms of the respective partnership agreements and did not involve any vote, consent or approval by the limited partners. The employee partnerships each have a set annual percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells we drill or acquire for our own account during the year in which the partnership was formed. The total interest the participants have in our oil and natural gas wells by participating in these partnerships does not exceed one percent.

Under the terms of our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions regarding 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 and the general partner are not the same, conflicts of interest will exist and it is not possible to entirely eliminate these 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 these cases, the drilling operations are conducted under drilling contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate these conflicts.

These partnerships are further described in Notes 1 and 7 to the Consolidated Financial Statements in Item 8 of this report.

EMPLOYEES

As of March 1, 2005, we had approximately 2,339 employees in our land contract drilling operations, 113 employees in our oil and natural gas operations, 21 employees in our gas gathering and processing operations and 42 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

OPERATING AND OTHER RISKS

Our contract drilling operations are subject to the many hazards inherent in the drilling industry. These include injury or death to personnel, well 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 and gas gathering and processing operations are also subject to many of these similar risks. Any of these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others.

Generally, our drilling contracts provide for the division of responsibilities between us and our customers, and we seek to obtain indemnification from our drilling customers for some of these risks. When we use our own drilling rigs to drill oil and natural gas wells for our own account, the contractual indemnification provisions would not act to shift responsibility or liability to a third party. To the extent that we are unable to transfer these risks to our drilling customers, we seek protection through insurance. However, our insurance or our indemnification agreements, if any, may not adequately protect us against liability from the consequences of the hazards described above. In addition, even if we have insurance coverage, we may still have a degree of exposure based on the amount of our deductible or retention. The occurrence of an event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could result in substantial losses to us. In addition, we may not be able to obtain insurance to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

Exploration and development operations involve numerous risks that can and do result in dry holes, the failure to be able to produce oil and natural gas in commercial quantities and the inability to fully produce discovered oil or natural gas reserves. The cost of drilling, completing and operating wells is substantial and uncertain. Our operations may also 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 drilling crews and the delivery of equipment.

A majority of the wells in which we own an interest are operated by other parties. As a result, we have little control over the operations of those wells and this lack of control 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 on 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 oil and natural gas reserves deplete, with the rate of decline depending on the reservoir characteristics of each producing well. Unless we successfully replace the oil and natural gas reserves that we produce, our oil and natural gas reserves will decline, resulting eventually in a decrease in our oil and natural gas production, revenues and cash flow from operations. Historically, we have succeeded in increasing oil and natural gas reserves after taking production into account. However, we may not be able to continue to replace our oil and natural gas reserves in a manner consistent with our past history. Low prices of oil and natural gas also limit the kinds of oil and natural gas reserves that we can economically develop. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Our natural gas gathering and processing operations involve numerous risks that may result in the failure to recover our cost in the natural gas gathering and processing facilities. The cost of developing the gathering systems and processing plants is substantial and uncertain. Our operations may be curtailed, delayed or cancelled as a result of many things beyond our control, including:

- unexpected changes in the deliverability of natural gas reserves from the wells connected to the gathering systems;
- availability of connecting pipelines in the area;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements;
- delays in the development of other producing properties within the gathering system's area of operation; and
- demand for natural gas and its constituents.

Many of the wells from which we gather and process natural gas are operated by other parties. As a result, we have little control over the operations of those wells which can act to increase our risk. Operators of those wells may act in ways that are not in our best interests.

GOVERNMENTAL REGULATIONS

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

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

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

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

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

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

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

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

SAFE HARBOR STATEMENT

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by or on our behalf, contain, or may contain, certain statements that are "forward-looking statements" within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which we expect or anticipate will or may occur in the future are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" and similar expressions are used to identify forward-looking statements.

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

- the amount and nature of our future capital expenditures;
- wells to be drilled or reworked;
- prices for oil and natural gas;
- demand for oil and natural gas;
- exploitation and exploration prospects;
- estimates of proved oil and natural gas reserves;
- oil and natural gas 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;
- growth potential for our gathering and processing operations;
- gathering systems and processing plants to be constructed or acquired;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations; and
- demand for our drilling rigs and drilling rig rates.

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

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

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

In order to provide a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines certain factors that in the future could cause our consolidated results for 2005 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

Commodity Prices. The prices we receive for our oil and natural gas production have a direct impact on our revenues, profitability and our cash flow as well as our ability to meet our projected financial and operational goals. The prices for natural gas and crude oil are heavily dependent on a number of factors beyond our control, including:

- the demand for oil and/or natural gas;
- current weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas);
- the amount and timing of liquid natural gas imports; 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 because of adverse weather conditions.

Oil prices are extremely sensitive to foreign influences 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 week-to-week and month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2004 production, a $.10 per Mcf change in what we receive for our natural gas production would result in a corresponding $211,800 per month ($2,541,600 annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price would have a $81,300 per month ($975,600 annualized) change in our pre-tax operating cash flow. During 2004, 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 future increases in prices. A more thorough discussion of our hedging or swap arrangements is contained in the Management's Discussion and Analysis of Financial Condition and Results of Operation section of this report contained in Item 7.

Drilling Customer Demand. With the exception of the drilling we do for our own account, the demand for our drilling services depends entirely on the needs of third parties. Based on past history, these parties' requirements are subject to a number of factors, independent of any subjective factors, that directly impact the demand for our drilling rigs. These factors include the availability of funds to carry out their drilling operations. For many of these parties, even if they have the funds available, their decision to spend those funds is often impacted by the then current prices for oil and natural gas. Many of our customers are small to mid-size oil and natural gas companies whose drilling budgets tend to be susceptible to the influences of current price fluctuations. Other factors that affect our ability to work our drilling rigs are: the weather which, under adverse circumstances, can delay or even cause the abandonment of a project by an operator; the competition faced by us in securing the award of a drilling contract in a given area; our experience and recognition in a new market area; and the availability of labor to run our drilling rigs.

Uncertainty of Oil and Natural Gas Reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The oil and natural gas reserve data included in this report represents only an estimate of these reserves. Oil and natural gas 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 oil and natural gas reserves based on risk of recovery, and estimates of the future net cash flows from oil and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to our oil and natural gas reserves will likely vary from estimates, and those variances may be material.

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

- the amount and timing of oil and natural gas production;
- supply and demand for oil and natural gas;

- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for use in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the 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 this "ceiling test" generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if we exceed the ceiling, even if prices are depressed for only a short period of time. We may be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings but would not impact our cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those we have consummated to date. 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 incurred and currently expect to continue to incur substantial working capital expenditures because of the growth in our contract drilling operations, our ongoing exploration and development programs and our expanding natural gas purchasing, gathering and processing operations. Historically, we have funded our working capital needs through a combination of internally generated cash flow, equity financing and borrowings under our bank credit agreement. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2004, our outstanding long-term debt was $95.5 million.

Our level of debt, the cash flow needed to satisfy our debt and the covenants contained in our bank credit agreement could:

- limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;
- place us at a competitive disadvantage to those of our competitors that are less indebted than we are;
- 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 obligations depends on our future performance. If the requirements of our indebtedness are not satisfied, a default could be deemed to occur and our lenders would be entitled to accelerate the payment of the outstanding indebtedness. If that were to occur, we would not have sufficient funds available and probably would not be able to obtain the financing required to meet our obligations.

The amount of our existing debt, as well as our future debt, is, to a large extent, a function of the costs associated with the projects we undertake at any given time and the cash flow we receive. Generally, our normal operating costs are those incurred as a result of the drilling of oil and natural gas wells, the acquisition of producing properties, the costs associated with the maintenance or expansion of our drilling rig fleet, and the operations of our natural gas purchasing, gathering and processing systems. To some extent, these costs, particularly the first two items, are discretionary and we maintain a degree of control regarding the timing 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, if our cash flow should prove to be insufficient to cover our current cash requirements we would need to increase our debt either through bank borrowings or otherwise.

Executive Officers. The table below and accompanying text sets forth certain information concerning each of our executive officers as of March 1, 2005.

NAME	AGE	POSITION HELD
John G. Nikkel (1)	70	Chairman of the Board since August 1, 2003 Director since 1983 Chief Executive Officer since July 1, 2001 President and Chief Operating Officer from 1983 to August 1, 2003
Larry D. Pinkston (1)	50	Director since January 15, 2004 President since August 1, 2003 Chief Operating Officer since February 24, 2004 Vice President and Chief Financial Officer from May 1989 to February 24, 2004
Mark E. Schell	47	Senior Vice President since December 2002 General Counsel and Corporate Secretary since January 1987
David T. Merrill	44	Chief Financial Officer and Treasurer since February 24, 2004 Vice President of Finance from August 2003 to February 24, 2004

(1) Mr. Nikkel has announced his intention to retire as our Chief Executive Officer effective April 1, 2005. Effective with Mr. Nikkel's retirement, the Board of Directors has elected Mr. Pinkston to succeed Mr. Nikkel as our Chief Executive Officer.

Mr. Nikkel joined Unit as its President, Chief Operating Officer and a director in 1983. He was elected its Chief Executive Officer in July, 2001 and Chairman of the Board in August, 2003. He currently holds the position of Chairman of the Board and Chief Executive Officer. From 1976 until January, 1982 when he co-founded Nike Exploration Company, Mr. Nikkel was an officer and director of Cotton Petroleum Corporation, serving as the President of Cotton from 1979 until his departure. Prior to joining Cotton, Mr. Nikkel was employed by Amoco Production Company for 18 years, last serving as Division Geologist for Amoco's Denver Division. Mr. Nikkel presently serves as President and a director of Nike Exploration Company. From August 16, 2000 until August 23, 2002 Mr. Nikkel, in connection with Unit's investment in the company, also served as a director of Shenandoah Resources Ltd., a Canadian company. Shenandoah Resources Ltd. filed for creditors' protection under The Companies' Creditor Arrangement Act in April 2002 with the Court of Queen's Bench of Alberta, Judicial District of Calgary. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Pinkston joined Unit in December, 1981. He had served as Corporate Budget Director and Assistant Controller prior to being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President of the company. He was elected a director of the company by the Board in January, 2004. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer. Mr. Pinkston holds the offices of President and Chief Operating

Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

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

Mr. Merrill joined Unit in August 2003 and served as its Vice President of Finance until February 2004 when he was elected to the position of Chief Financial Officer and Treasurer. From May 1999 through August 2003, Mr. Merrill served as Senior Vice President, Finance with TV Guide Networks, Inc. From July 1996 through May 1999 he was a Senior Manager with Deloitte & Touche LLP. From July 1994 through July 1996 he was Director of Financial Reporting and Special Projects for MAPCO, Inc. He began his career as an auditor with Deloitte, Haskins & Sells in 1983. Mr. Merrill received a Bachelor of Business Administration Degree in Accounting from the University of Oklahoma and is a Certified Public Accountant.

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 2004.

PART II

Item 5. *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

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

	2004		2003	
QUARTER	High	Low	High	Low
First	$27.85	$23.10	$21.99	$16.30
Second	$31.45	$25.87	$23.39	$19.14
Third	$35.19	$29.55	$22.60	$18.68
Fourth	$40.63	$33.88	$24.51	$18.40

On March 1, 2005 there were 1,606 record holders of our common stock.

We have never paid cash dividends on our common stock and currently intend to continue our policy of retaining earnings from our operations. Our credit agreement prohibits us from declaring and paying dividends (other than stock dividends) in any fiscal year in an amount greater than 25% of our preceding year's consolidated net income.

Item 6. *Selected Financial Data*

	As of and for the Year Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands except per share amounts)				
Revenues	$ 519,203	$301,377	$187,392	$258,397	$201,387
Income Before Cumulative Effect of Change In Accounting Principle	$ 90,275	$ 48,864	$ 18,244	$ 62,766	$ 34,344
Net Income	$ 90,275	$ 50,189	$ 18,244	$ 62,766	$ 34,344
Income Before Cumulative Effect of Change In Accounting Principle per Common Share:					
Basic	$ 1.97	$ 1.12	$ 0.47	$ 1.75	$ 0.96
Diluted	$ 1.97	$ 1.12	$ 0.47	$ 1.73	$ 0.95
Net Income per Common Share:					
Basic	$ 1.97	$ 1.15	$ 0.47	$ 1.75	$ 0.96
Diluted	$ 1.97	$ 1.15	$ 0.47	$ 1.73	$ 0.95
Total Assets	$1,023,136	$712,925	$578,163	$417,253	$346,288
Long-Term Debt	$ 95,500	$ 400	$ 30,500	$ 31,000	$ 54,000
Other Long-Term Liabilities	$ 37,725	$ 17,893	$ 5,439	$ 4,110	$ 3,597
Cash Dividends per Common Share	$ —	$ —	$ —	$ —	$ —

See Item 7. Management's Discussion of Financial Condition and Results of Operation for a review of 2004, 2003 and 2002 activity.

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

FINANCIAL CONDITION AND LIQUIDITY

Summary. Our financial condition and liquidity depends on the cash flow from our three principal business segments (and our subsidiaries that carry out those operations) and borrowings under our bank credit agreement. Our cash flow is influenced mainly by:

- the prices we receive for our natural gas production and, to a lesser extent, the prices we receive for our oil production;
- the quantity of natural gas we produce;
- the demand for and the dayrates we receive for our drilling rigs; and
- the margins we obtain from our natural gas gathering and processing contracts.

At December 31, 2004, we had cash totaling $665,000 and we had borrowed $95.5 million of the $150.0 million we had elected to have available under our credit agreement.

Our three principal business segments are:

- contract drilling carried out by our subsidiaries Unit Drilling Company and Service Drilling Southwest, L.L.C. until it was merged into Unit Drilling Company on December 31, 2004, we also operated through our subsidiary Sauer Drilling Company;
- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company and, until it was merged into Unit Petroleum Company in March 2005, PetroCorp Incorporated; and
- natural gas purchasing, gathering and processing carried out by our subsidiary Superior Pipeline Company, L.L.C.

The following is a summary of certain financial information as of December 31, 2004 and for the years ended December 31, 2004 and December 31, 2003:

	December 31, 2004	December 31, 2003	Percent Change
	(In thousands except percent amounts)		
Working Capital	$ 41,425	$ 20,931	98%
Long-Term Debt	$ 95,500	$ 400	23,775%
Shareholders' Equity	$ 608,269	$ 515,768	18%
Ratio of Long-Term Debt to Total Capitalization	13.6%	— %	— %
Income Before Cumulative Effect of Change in Accounting Principle	$ 90,275	$ 48,864	85%
Net Income	$ 90,275	$ 50,189	80%
Net Cash Provided by Operating Activities	$ 203,210	$ 121,712	67%
Net Cash Used in Investing Activities	$(301,972)	$(132,099)	129%
Net Cash Provided by Financing Activities	$ 98,829	$ 10,488	842%

The following table summarizes certain operating information for the years ended December 31, 2004 and 2003:

	2004	2003	Percent Change
Oil Production (MBbls)	1,048	516	103%
Natural Gas Production (MMcf)	27,149	20,648	31%
Average Oil Price Received	$ 33.20	$ 26.94	23%
Average Oil Price Received Excluding Hedge	$ 36.63	$ 26.95	36%
Average Natural Gas Price Received	$ 5.42	$ 4.87	11%
Average Natural Gas Price Received Excluding Hedge	$ 5.42	$ 4.87	11%
Average Number of Our Drilling Rigs in Use During the Period	88.1	62.9	40%
Total Number of Drilling Rigs Available at the End of the Period	100	88	14%
Gas Gathered—MMBtu/day	33,147	16,413	102%
Gas Processed—MMBtu/day	13,412	92	14,478%
Number of Natural Gas Gathering Systems	32	15	113%

Our Bank Credit Agreement. At December 31, 2004, we had a $150.0 million bank credit agreement consisting of a revolving credit facility maturing on January 30, 2008. Borrowings under the credit facility are limited to a commitment amount and we have currently elected to have the full $150.0 million available as the commitment amount. We are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We incurred origination, agency and syndication fees of $515,000 at the inception of the agreement, $40,000 of which will be paid annually and the remainder of the fees amortized over the four year life of the loan. The average interest rate for 2004 was 2.8%. At December 31, 2004 and March 1, 2005 our borrowings were $95.5 million and $88.0 million, respectively.

The borrowing base under our credit facility is subject to re-determination on May 10 and November 10 of each year. The latest re-determination supported the full $150.0 million. Each re-determination is based primarily on the sum of a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a small part of the value of our drilling rig fleet, limited to $20.0 million, is added to the loan value. The credit agreement allows for one requested special re-determination of the borrowing base by either the banks or us between each scheduled re-determination date.

At our election, any portion of the outstanding debt may be fixed at a London Interbank Offered Rate (LIBOR) for 30, 60, 90 or 180 day terms. During any LIBOR Rate funding period the outstanding principal balance of the note to which a LIBOR Rate option applies may be repaid after providing three days notice to the administrative agent and on the payment of any required indemnification amounts. Interest on the LIBOR Rate is computed at the LIBOR Base Rate applicable for the interest period plus 1.00% to 1.50% depending on the level of debt as a percentage of the total loan value and is payable at the end of each term or every 90 days whichever is less. Borrowings not under the LIBOR Rate bear interest at the JPMorgan Chase Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At December 31, 2004, all of our $95.5 million debt was subject to the LIBOR Rate.

The credit agreement includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain very limited exceptions and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of our banks.

The credit agreement also requires that we have at the end of each quarter:

- a consolidated net worth of at least $350.0 million,

- a current ratio (as defined in the credit agreement) of not less than 1 to 1 and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On December 31, 2004, we were in compliance with the covenants of the credit agreement.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 2008. This period coincides with the remaining length of our current credit facility. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge.

Contractual Commitments. At December 31, 2004, we had the following contractual obligations:

	Payments Due by Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Bank Debt (1)	$104,625	$2,961	$5,921	$95,743	$—
Retirement Agreement (2)	1,500	350	700	450	—
Operating Leases (3)	4,230	1,167	1,929	1,090	44
SerDrilco Inc. Earn-Out Agreement (4)	1,890	1,890	—	—	—
Total Contractual Obligations	$112,245	$6,368	$8,550	$97,283	$ 44

(1) See Previous Discussion in Management Discussion and Analysis regarding bank debt. This obligation is presented in accordance with the terms of the credit agreement signed on January 30, 2004 and includes interest calculated at our year end interest rate of 3.1%.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, will be paid in monthly payments of $25,000 starting in July 2003 and continuing through June 2009. In the first quarter of 2004, we acquired a liability for the present value of a separation agreement between PetroCorp Incorporated and one of its previous officers. The liability associated with this last agreement will be paid in quarterly payments of $12,500 through December 31, 2007. Both liabilities as presented above are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma and Midland and Houston, Texas under the terms of operating leases expiring through January 31, 2010. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess rig equipment and production inventory.

(4) On December 8, 2003, the company acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10.0 million for each of the three years following the acquisition. For the year ending December 31, 2004, the drilling rigs included in the earn-out provision had cash flow of approximately $13.8 million.

On October 19, 2004, Mr. John Nikkel, the Company's Chairman of the Board of Directors and Chief Executive Officer, announced that he plans to retire as an employee and as the Company's Chief Executive Officer effective April 1, 2005. Mr. Nikkel intends to continue as a director of the Company. In connection with his retirement, the Board of Directors and Mr. Nikkel reached an agreement which was memorialized on December 17, 2004, providing for the following:

- Mr. Nikkel would serve as a consultant to the company, on an annual basis, for $70,000 per year and, the parties, by mutual written agreement, may extend the term of this agreement for successive one year periods at any time before the termination of the then existing term of the agreement; and

- The company would provide office space and secretarial service for Mr. Nikkel for the time he serves as a consultant to the company.

On February 16, 2005, the Compensation Committee of the Board of Directors elected to reward Mr. Nikkel for his 21 years of exemplary service to the company by awarding him a cash bonus of $750,000, payable in 24 equal monthly installments commencing on the 20th month following his retirement on April 1, 2005.

In the first quarter of 2005 we made a commitment to purchase approximately $12.0 million of drill pipe and drill collars for delivery during 2005. Also in the first quarter of 2005, our oil and natural gas segment made a commitment to purchase $5.2 million of tubing and casing for delivery during the first quarter of 2005.

At December 31, 2004, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Amount of Commitment Expiration Per Period			
Other Commitments	**Total Accrued**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Deferred Compensation Agreement (1)	$ 2,111	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement (2)	$ 2,821	$ 700	$ 203	Unknown	Unknown
Plugging Liability (3)	$19,135	$ 226	$ 494	$ 1,822	$ 16,593
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	$ 0	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$17,175	$ 4,561	$ 5,021	$ 1,449	$ 6,144

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

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan. This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the Unit. As of December 31, 2004, there were no participants in this plan.

(3) On January 1, 2003, we adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled or acquired).

(4) We have recorded a liability for certain properties where we believe there are insufficient oil and natural gas reserves available to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees,

officers and directors from 1984 through 2004, with a subsidiary of ours serving as General Partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined in accordance with the terms of the partnership agreement in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $14,000, $106,000 and $1,000 in 2004, 2003 and 2002, respectively, for such limited partners' interests.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims made primarily in our contract drilling segment.

Hedging. Periodically we hedge the prices we will receive for a portion of our future natural gas and oil production. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow.

On April 30, 2002, we entered into a natural gas collar contract for 10,000 MMBtu's of production per day that covered the period of April 1, 2002 through October 31, 2002. The collar had a floor of $3.00 and a ceiling of $3.98. During the year of 2002, our natural gas hedging transactions increased natural gas revenues by $40,300. We did not have any hedging transactions outstanding at December 31, 2002. These hedges were cash flow hedges and there was no material amount of ineffectiveness.

During the first quarter of 2003, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day and covered the periods of April through September 2003. One contract had a floor of $4.00 and a ceiling of $5.75 and the other contract had a floor of $4.50 and a ceiling of $6.02. During the first quarter of 2003, we also entered into two oil collar contracts. Each contract was for 5,000 barrels of production per month and covered the period of May through December 2003. One contract had a floor price of $25.00 and a ceiling of 32.20 and the other contract had a floor price of $26.00 and a ceiling of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. During the year of 2003, the collar contracts decreased natural gas revenues by $6,000 and oil revenues by $5,000. We did not have any hedging transactions outstanding at December 31, 2003.

During the first and second quarters of 2004, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covered the period of April through October of 2004 and had a floor of $4.50 and a ceiling of $6.76. The other contract covered the period of May through October of 2004 and had a floor of $5.00 and a ceiling of $7.00. We also entered into an oil hedge covering 1,000 barrels per day of oil production. The transaction covered the periods of February through December of 2004 and had an average price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. The natural gas collar contracts increased natural gas revenues by $48,000 during 2004. Oil revenues were reduced by $3.6 million in 2004 due to the settlement of the oil hedge. We did not have any hedging transactions outstanding at December 31, 2004.

In January 2005, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covered the period of April through October of 2005 and had a floor of $5.50 and a ceiling of $7.19. The other contract covered the period of April through October of 2005 and had a floor of $5.50 and a ceiling of $7.30. These hedges are cash flow hedges and there is no material amount of ineffectiveness.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 2008. This period coincides with the remaining length of our current credit facility. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge.

Self-Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. Our insurance policies contain deductibles or retentions per occurrence ranging from $200,000 for general liability to $1.0 million for drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain claims. There is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco we have continued to use its ERISA governed occupational injury benefit plan to cover its employees in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas. After the acquisition of PetroCorp Incorporated (as further discussed in Note 2 of the Notes to Consolidated Financial Statements), natural gas comprises 85% of our total oil and natural gas reserves. Before the acquisition, natural gas comprised 89% of our oil and natural gas reserves. Any significant change in natural gas prices has a material affect on our revenues, cash flow and the value of our oil and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our production in 2004, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $211,800 per month ($2,541,600 annualized) change in our pre-tax operating cash flow. Our 2004 average natural gas price was $5.42 compared to an average natural gas price of $4.87 for 2003. A $1.00 per barrel change in our oil price would have a $81,300 per month ($975,600 annualized) change in our pre-tax operating cash flow based on our production in 2004. Our 2004 average oil price was $33.20 compared with an average oil price of $26.94 received in 2003.

Because natural gas prices have such a significant affect on the value of our oil and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our bank credit agreement since that determination is based mainly on the value of our oil and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

Most of our natural gas production is sold to third parties under month-to-month contracts. For 2004, purchases by Eagle Energy Partners I, L.P. accounted for approximately 25% of our oil and natural gas revenues while purchases by Cinergy Marketing and Trading L.P. accounted for approximately 11% of our oil and natural gas revenues.

On August 2, 2004, we completed the sale of our 16.7% limited partner interest in Eagle Energy Partners I, L.P. Eagle's purchase of natural gas from us during 2004 accounted for 25% of our oil and natural gas revenues during 2004. Eagle also marketed approximately 55% of the natural gas volumes we sold for ourselves as well as third parties during the same period. For the period August through December 2003, Eagle's purchases from us accounted for 16% of our oil and natural gas revenues and it marketed approximately 37% of the natural gas volumes we sold for ourselves as well as third parties during the same five month period.

Oil and Natural Gas Acquisitions and Capital Expenditures. On January 30, 2004, we acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash. At the closing of this acquisition, PetroCorp had $97.9 million in working capital. PetroCorp explored and developed oil and natural gas properties primarily in Texas and Oklahoma. Approximately 84% of the oil and natural gas properties acquired in the acquisition are located in the Mid-Continent and Permian basins, while 6% are located in the Rocky Mountains and 10% are located in the Gulf Coast basin. The acquired properties increased our oil and natural gas reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide us with additional locations for future development drilling. The results of operations for this acquired company are included in the statement of income for the period after January 31, 2004.

Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when to incur such costs. We drilled 168 wells (69.49 net wells) in 2004 compared to 149 wells (61.57 net wells) in 2003. Our total capital expenditures for oil and natural gas exploration and acquisitions in 2004 totaled $215.1 million with $114.3 million relating to the PetroCorp acquisition. Included in the PetroCorp acquisition was a plugging liability and deferred tax liability of $31.6 million.

Based on current prices, we plan to drill an estimated 220 to 230 wells in 2005 and estimate our total capital expenditures for oil and natural gas exploration and acquisitions to be around $125.0 million. In 2004, due to anticipated increases in steel product costs, we increased our inventory of production casing and tubing from $3.1 million to $8.4 million in 2004. This inventory will be used to meet our continued demand for such items as we complete wells in our development drilling program. In the first quarter of 2005, we made a commitment to purchase $5.2 million of tubing and casing for delivery during the first quarter of 2005.

Contract Drilling. Our drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our drilling rigs and our ability to supply the equipment needed. Because of the current high demand for drilling rigs we are experiencing some difficulty in hiring and keeping all of the rig crews we need.

In response, at the end of the first and fourth quarters of 2004, we increased wages in some of our drilling areas and implemented longevity pay incentives to help maintain our contract drilling labor base. To date, these efforts have allowed us to meet our labor requirements. If current demands for drilling rigs continues, shortages of experienced personnel may limit our ability to operate our drilling rigs at or above the 95% utilization rate we achieved in the fourth quarter of 2004.

We currently do not have a shortage of drill pipe. Because of increasing steel costs and the potential for future shortages in the availability of new drill pipe, we committed in the first quarter of 2004 to purchase approximately 275,000 feet of drill pipe for $9.3 million. At December 31, 2004 we had accepted delivery of all of the pipe under the commitment. Early in 2005, we committed to the purchase of another $12.0 million of drill pipe and collars during 2005.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs and the prices we can charge for our contract drilling services. The average rates we received for our drilling rigs during 2003 and 2004 reached a low of $7,275 per day in February of 2003. However, as natural gas and oil prices began to rise during the second quarter of 2003 and have continued to remain strong through 2004, both demand for our drilling rigs and dayrates have improved. In 2004, the average dayrate we received was $8,937 per day compared to $7,808 per day in 2003. The average use of our drilling rigs in 2004 was 88.1 drilling rigs (95%) compared with 62.9 rigs (83%) for 2003. Based on the average utilization of our drilling rigs during 2004, a $100 per day change in dayrates has an $8,810 per day ($3,216,000 annualized) change in our pre-tax operating cash flow. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiary provides drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties for comparable type projects. During 2004 and 2003, we drilled 35 and 43 wells, respectively, for our exploration and production subsidiary. The profit received by our contract drilling segment of $3.7 million and $1.9 million during 2004 and 2003, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Drilling Acquisitions and Capital Expenditures. On July 30, 2004, we completed our acquisition of Sauer Drilling Company, a Casper, Wyoming-based drilling company. We paid $40.3 million in this acquisition which included $5.3 million for working capital. This acquisition included nine drilling rigs, a fleet of trucks, and an equipment and repair yard containing associated inventory located in Casper, Wyoming. The drilling rigs range from 500 horsepower to 1,000 horsepower with depth capacities rated from 5,000 feet to 16,000 feet. The fleet of trucks consists of four vacuum trucks, and 11 rig-up trucks which are used to move the drilling rigs to new drilling locations. The trucks are also used to move other company's drilling rigs. This acquisition increased our market share in the Rocky Mountains in the medium-to-smaller drilling rig depth ranges. The Casper, Wyoming equipment yard will continue to provide service space for the nine newly acquired drilling rigs and trucks as well as our other existing Rocky Mountain drilling rig fleet. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004.

On May 4, 2004, we acquired two drilling rigs and related equipment for $5.5 million. The drilling rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. We refurbished these drilling rigs for approximately $4.0 million. One drilling rig was placed into service at the beginning of August 2004 and the other drilling rig was placed into service in the middle of September 2004. Both drilling rigs are working in our Rocky Mountain Division.

With these two acquisitions and the completion of construction of another 1,500 horsepower diesel electric drilling rig in June 2004, our total drilling rig fleet at December 31, 2004 was 100 drilling rigs.

On January 5, 2005 we acquired a subsidiary of Strata Drilling LLC for $10.5 million in cash. This acquisition included two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two drilling rigs are 1,500 horsepower, diesel electric drilling rigs with the capacity to drill 12,000 to 20,000 feet. One drilling rig is currently operating and the other drilling rig will require approximately $2.0 million in expenditures to complete. This last drilling rig should be fully operational within 90 days. Both drilling rigs will ultimately be placed into service in our Rocky Mountain Division.

Also in January 2005, we completed the construction of a new 1,500 horsepower diesel electric drilling rig. This drilling rig is now operating in our Anadarko Basin Division. The addition of this drilling rig, along with the two drilling rigs we acquired in the transaction with Strata Drilling, L.L.C., brings our total rig fleet as of March 1, 2005 to 103 drilling rigs.

We plan to start the construction of our 104th drilling rig in the first quarter of 2005. This drilling rig will be a 1,500 horsepower diesel electric drilling rig and, when completed, will be added to our Rocky Mountain Division.

For our contract drilling operations during 2004, we incurred $98.4 million in capital expenditures, which includes $34.9 million in connection with the Sauer acquisition. For 2005, we have budgeted capital expenditures of approximately $60.0 million for our contract drilling operations.

Acquisition of Natural Gas Gathering and Processing Company. In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior Pipeline Company, L.L.C. we did not already own. We paid $19.8 million in this acquisition. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas. It operates one natural gas treatment plant, owns three processing plants, 32 active gathering systems and 440 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana and has been in business since 1996. This acquisition and consolidation increases our ability to gather and market our natural gas (as well as third party natural gas) and construct or acquire existing natural gas gathering and processing facilities.

Before this acquisition, our 40% interest in the operations of Superior was shown as equity in earnings of unconsolidated investments. Our investment, including our share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets on our accompanying 2003 balance sheet. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. During 2004, Superior purchased $4.0 million of our natural gas production and paid $97,000 for our natural gas liquids. After the acquisition of Superior, $1.8 million of the natural gas purchased and $53,000 of the natural gas liquids purchased were eliminated.

For the year 2005, we have budgeted capital expenditures of approximately $20.0 million for our natural gas gathering and processing operation with the focus on growing this segment through the construction of new facilities or acquisitions.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner of 11 oil and natural gas partnerships which were formed privately and publicly. Each partnership's revenues and costs are shared under formulas prescribed in its limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. During 2004, 2003 and 2002, the total paid to us for all of these fees was $746,000, $873,000 and $929,000, respectively. We expect that these fees in 2005 will be comparable to those in 2004. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

On August 2, 2004, we completed the sale of our investment in Eagle Energy Partners I, L.P. for $6.2 million. In the third quarter of 2004, a gain before income taxes of $3.8 million was recognized in other revenues from this sale. Eagle marketed approximately 55% of the natural gas volumes we sold for ourselves and other parties in 2004.

Critical Accounting Policies.

Summary

In this section, we have identified the critical accounting policies we follow in preparing our financial statements and related disclosures. Many of these policies require us to make difficult, subjective and complex judgments in the course of making estimates of matters that are inherently imprecise. We will explain the nature of these estimates, assumptions and judgments, and the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

The following table lists our critical accounting policies, the estimates and assumptions that can have a significant impact on the application of these accounting policies, and the financial statement accounts affected by these estimates and assumptions.

Accounting Policies	Estimates or Assumptions	Accounts Affected
Full cost method of accounting for oil and gas properties	• Oil and natural gas reserves estimates and related present value of future net revenues	• Oil and gas Properties • Accumulated DD&A • Provision for DD&A
	• Valuation of unproved properties	• Impairment of proved and unproved properties • Long-term debt and interest expense

Accounting Policies	Estimates or Assumptions	Accounts Affected
Accounting for asset retirement obligations for oil and gas properties	• Cost estimates Related to the plugging and abandonment of wells	• Oil and gas properties • Accumulated DD&A • Provision for DD&A • Current and non-current liabilities • Operating expense
Accounting for impairment of drilling property and equipment	• Forecast of undiscounted estimated future net operating cash flows	• Drilling property and equipment • Accumulated depreciation • Provision for depreciation • Impairment of drilling property and equipment
Turnkey and footage drilling contracts	• Estimates of costs to complete turnkey and footage contracts	• Revenue and operating expense • Current assets and liabilities

Significant Estimates and Assumptions

Oil and natural gas reserve engineering is a subjective process. It entails estimating underground accumulations of oil and natural gas. These accumulations cannot be measured in an exact manner. The degree of accuracy of these estimates depends on a number of factors, including, the quality of available geological and engineering data, the precision of the interpretations of that data, and judgment based on experience and training. Annually, we engage an independent petroleum engineering firm to audit our internal evaluation of our oil and natural gas reserves.

The techniques used in estimating oil and natural gas reserves annually depend on the nature and extent of available data and the accuracy of the estimates. As a general rule, the degree of accuracy of oil and natural gas reserve estimates varies with the reserve classification and the related accumulation of available data, as shown in the following table:

Type of Reserves	Nature of Available Data	Degree of Accuracy
Proved undeveloped	Data from offsetting wells, seismic data	Least accurate
Proved developed non-producing	Logs, core samples, well tests, pressure data	More accurate
Proved developed producing	Production history, pressure data over time	Most accurate

Assumptions as to future commodity prices and operating and capital costs also play a significant role in estimating oil and natural gas reserves and the estimated present value of the cash flows to be received from the future production of those reserves. Volumes of recoverable reserves are affected by the assumed prices and costs due to what is known as the economic limit (that point in the future when the projected costs and expenses of producing recoverable oil and natural gas reserves exceed the projected revenues from the oil and natural gas reserves). But more significantly, the estimated present value of future cash flows from the oil and natural gas reserves is extremely sensitive to prices and costs, and may vary materially based on different assumptions. SEC financial accounting and reporting standards require that pricing parameters be tied to the price received for oil and natural gas on the last day of the reporting period. This requirement can result in significant changes from period to period given the volatile nature of oil and natural gas prices. Based on our year end 2004 oil and natural gas reserves, a $1.00 decline in the oil price used to calculate our economically recoverable oil reserves will reduce our estimated oil reserves by 32,000 barrels and a $0.10 decline in the price of natural gas used to calculate our natural gas reserves will reduce our estimated economically recoverable natural gas reserves by 386,000 Mcf. Estimated future cash flows discounted at 10% before income taxes would change by $19.4 million.

We compute our provision for DD&A on a units-of-production method. Each quarter, we use the following formulas to compute the provision for DD&A for our producing properties:

- DD&A Rate = Unamortized Cost / Beginning of Period Reserves
- Provision for DD&A = DD&A Rate x Current Period Production

Oil and natural gas reserve estimates have a significant impact on the DD&A rate. If reserve estimates for a property or group of properties are revised downward in future periods, the DD&A rate will increase as a result of the revision. Alternatively, if reserve estimates are revised upward, the DD&A rate will decrease. At our 2004 production level of 33,437,000 equivalent Mcf, a 5% change in the amount of our 2004 oil and natural gas reserves would change our DD&A rate by $0.07 per mcfe and would change pre-tax income by $2.4 million annually.

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

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have large downward revisions in our estimated proved oil and natural gas reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil and natural gas prices on December 31, 2004 ($5.65 per Mcf for natural gas and $43.45 per barrel for oil), the unamortized cost of our oil and natural gas properties did not exceed the ceiling of our proved oil and natural gas reserves. Natural gas and oil prices remain erratic and any significant declines below prices used in the reserve evaluation could result in a ceiling test write-down in following quarterly reporting periods.

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

On January 1, 2003 the company adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. We own oil and natural gas properties which require costs to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling these plugging liabilities. Our engineering staff uses historical experience to determine estimated plugging costs taking into account the type of well (either oil or natural gas), the depth of the well and physical location of the well within our areas of operation to determine the estimated plugging costs. Since the implementation of this standard, we have not plugged enough wells to make additional determinations as to the accuracy of the estimates.

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

Because we do not bear the risk of completion of a well drilled under a “daywork” contract we recognize revenues and expense generated under “daywork” contracts as the services are performed. Under “footage” and “turnkey” contracts, we bear the risk of completion of the well, so revenues and expenses are recognized when the well is substantially completed. Substantial completion is determined when the well bore reaches the depth specified in the contract. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the well is finished. The costs of drilling contracts uncompleted at the end of the reporting period (which includes expenses incurred to date on “footage” or “turnkey” contracts) are included in other current assets. In 2004, we did not drill any footage or turnkey contracts.

EFFECTS OF INFLATION

The effect of inflation in the oil and natural gas industry is primarily driven by the prices for oil and natural gas. Increased commodity prices increase demand for contract drilling rigs and services which support higher drilling rig activity. This in turn affects the overall demand for our drilling rigs and the dayrates we can obtain for our contract drilling services. Before 1999, the effect of inflation on our operations was minimal due to low inflation rates, relatively low natural gas and oil prices and moderate demand for our contract drilling services. Over the last five years natural gas and oil prices have been more volatile, and during periods of higher utilization we have experienced increases in labor cost and the cost of services to support our drilling rigs. During this same period, when commodity prices did decline labor rates did not come back down to the levels existing before the increases. If natural gas prices increase substantially for a long period, shortages in support equipment (such as drill pipe, third party services and qualified labor) will result in additional increases in our material and labor costs. These conditions may limit our ability to realize improvements in operating profits. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates and the prices we receive for our oil and natural gas.

NEW ACCOUNTING PRONOUNCEMENTS

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

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

In September 2004, the staff of the SEC issued Staff Accounting Bulletin No. 106 (SAB 106) to express the staff's views regarding application of FAS 143, "Accounting for Asset Retirement Obligations," by oil and natural gas producing companies following the full cost accounting method. SAB 106 addressed the computation of the full cost ceiling test to avoid double-counting asset retirement costs, the disclosures a full cost accounting company is expected to make regarding the impacts of FAS 143, and the amortization of estimated dismantlement and abandonment costs that are expected to result from future development activities. The accounting and disclosures described in SAB 106 have been adopted by the Company as of the fourth quarter of 2004 and did not have a material impact on the financial position of the Company, or on its results of operations.

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. The Company has not determined the impact, if any, that this statement will have on its results of operations or its financial condition.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended Accounting Principles Board (APB) Opinion No. 29, "Accounting for Nonmonetary Transactions." FAS 153 requires that nonmonetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The Company does not expect this statement to have a material impact on it results of operations or its financial condition.

In December 2004, the FASB issued FAS 123R, which requires that compensation cost relating to share-based payments be recognized in the company's financial statements. We currently account for these payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. We are preparing to implement this standard effective July 1, 2005. Although the transition method to be used to adopt the standard has not been selected, see Employee and Director Stock Based Compensation section of Note 1 of the Notes to Consolidated Financial Statements in Item 8 of this report for the effect on net income and earnings per share for the years 2002 through 2004.

RESULTS OF OPERATIONS

2004 versus 2003

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

	2004	2003	Percent Change
Total Revenue	$519,203,000	$301,377,000	72%
Income Before Cumulative Effect of Change in Accounting Principle	$ 90,275,000	$ 48,864,000	85%
Net Income	$ 90,275,000	$ 50,189,000	80%
Oil and Natural Gas:			
Revenue	$185,017,000	$116,609,000	59%
Operating costs	$ 41,303,000	$ 24,953,000	66%
Average natural gas price (Mcf)	$ 5.42	$ 4.87	11%
Average oil price (Bbl)	$ 33.20	$ 26.94	23%
Natural gas production (Mcf)	27,149,000	20,648,000	31%
Oil production (Bbl)	1,048,000	516,000	103%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.41	$ 1.14	24%
Depreciation, depletion and amortization	$ 47,517,000	$ 27,343,000	74%
Gas Gathering and Processing:			
Revenue	$ 29,717,000	$ 606,000	4,804%
Operating costs	$ 27,018,000	$ 349,000	7,642%
Depreciation	$ 982,000	$ 176,000	458%
Gas gathered—MMBtu/day	33,147	16,413	102%
Gas processed—MMBtu/day	13,412	92	14,478%
Drilling:			
Revenue	$298,204,000	$183,146,000	63%
Operating costs	$210,912,000	$138,762,000	52%
Percentage of revenue from daywork contracts	100%	98%	2%
Average number of rigs in use	88.1	62.9	40%
Average dayrate on daywork contracts	$ 8,937	$ 7,808	14%
Depreciation	$ 33,659,000	$ 23,644,000	42%
General and Administrative Expense	$ 11,987,000	$ 9,222,000	30%
Interest Expense	$ 2,695,000	$ 693,000	289%
Average Interest Rate	2.8%	2.2%	27%
Average Long-Term Debt Outstanding	$ 83,121,000	$ 20,722,000	301%

Oil and natural gas revenues increased $68.4 million or 59% in 2004 as compared to 2003. Increased oil and natural gas prices accounted for 32% of this increase while increased production volumes accounted for 68% of the increase. The PetroCorp acquisition increased our oil production by 64% in 2004 while total oil production increased 103%. The PetroCorp acquisition increased our natural gas production for 2004 by 18% while our total natural gas production increased 31%. Increased production outside of the PetroCorp acquisition came primarily from our development drilling program.

Oil and natural gas operating cost increased $16.3 million or 66% in 2004 as compared to 2003. Cost directly related to the production of the PetroCorp wells that we acquired in January 2004 represented 37% of the increase while 27% came from production costs related to wells we drilled in 2004 and increases in production costs from previously drilled wells. Gross production taxes represented 25% of the increase because of higher oil and natural gas revenues. General and Administrative cost directly related to the production of our wells represented 6% of the increase as labor costs increased primarily because of a 32% addition in the number of employees working in our exploration and production area. Total depreciation, depletion and amortization ("DD&A") on our oil and natural gas properties increased $20.2 million or 74%. Higher production volumes were 55% of the increase and increases in the DD&A rate represented 45% of the increase. The increase in the DD&A rate in 2004 resulted from 63% higher development drilling cost per equivalent Mcf in 2004 versus 2003. PetroCorp's oil and natural gas reserves were added at a 5% higher cost per Mcf than our discovery cost in 2003.

Industry demand for our drilling rigs increased throughout 2004 as natural gas prices continued to remain above $4.50. Drilling revenues increased $115.1 million or 63% in 2004 versus 2003. In December 2003, we acquired 12 drilling rigs with the acquisition of SerDrilco, Inc. and its subsidiary, Service Drilling Southwest, L.L.C. Those drilling rigs increased our 2004 drilling revenues approximately 17%. In July 2004, we acquired nine drilling rigs with the acquisition of Sauer Drilling Company. The Sauer drilling rigs increased our 2004 drilling revenues by approximately 8%. The increase in revenue from all our acquired drilling rigs and increased utilization from our previously owned drilling rigs represented 67% of the total increase in revenues. Increases in dayrates and mobilization fees accounted for 33% of the increase in total drilling revenues. Our average dayrate in 2004 was 14% higher than our average dayrate in 2003.

Drilling operating costs were up $72.2 million or 52%. The 12 drilling rigs acquired with the acquisition of SerDrilco Inc. increased our 2004 operating cost by approximately 13% and the nine Sauer drilling rigs increased our 2004 operating costs by approximately 7%. The increase in operating cost from all our acquired drilling rigs and increased utilization from our previously owned drilling rigs represented 82% of the total increase in operating cost. Increases in operating cost per day accounted for 18% of the increase in total operating costs. Operating cost per day increased $501 per day in 2004 with approximately $360 of that increase coming from costs directly associated with the drilling of wells. Indirect drilling costs made up most of the remainder of the increase in per day costs and consisted primarily of property taxes, safety related expenses, repairs and the implementation of a central hiring system for our Oklahoma drilling rig fleet. We expect the demand for drilling rigs to remain high throughout 2005 and this will put additional upward pressure on our drilling rig expenses. Approximately 1% of our total drilling revenues in 2003 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. We did not drill any turnkey or footage wells in 2004. Contract drilling depreciation increased $10.0 million or 42%. The acquisition of the SerDrilco drilling rigs increased depreciation $3.5 million or 35% while the acquisition of the Sauer drilling rigs increased depreciation $1.3 million or 13% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

In July 2004, we consolidated and increased our natural gas gathering and processing business when we completed the acquisition of the 60% of Superior we did not already own. We paid $19.8 million in this acquisition. Before July 2004, we had developed 18 gathering systems which we have now consolidated with Superior's operations. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas and operates one natural gas treatment plant and owns three processing plants, 32 active gathering systems and 440 miles of pipeline. Superior operates in Oklahoma, Texas and Louisiana.

Before the Superior acquisition, our 40% interest in the income or loss from the operations of Superior was shown as equity in earnings of unconsolidated investments and was $603,000 net of income tax in 2004 versus $953,000 net of income tax in 2003. Our investment, including our share of the equity in the earnings of Superior, totaled $3.0 million at December 31, 2003 and is reported in other assets on our accompanying 2003 balance sheet. The results of operations for Superior are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between business segments has been eliminated. Our natural gas gathering and processing revenues, operating expenses and depreciation were $29.1 million, $26.7 million and $0.8 million higher, respectively, all due to the Superior acquisition.

General and administrative expense increased $2.8 million or 30%. Personnel costs increased $1.2 million, external audit fees and third party contractor costs primarily relating to the implementation of Sarbanes-Oxley increased $0.6 million and insurance costs increased $0.3 million.

Our total interest expense increased $2.0 million or 289%. Average debt outstanding increased in 2004 due to the PetroCorp, Superior and Sauer acquisitions. The cost of these acquisitions accounted for approximately 80% of the interest increase with the remainder coming from an increase in average interest rates. Income tax expense increased $24.9 million or 86% primarily due to the increase in income before income taxes. Our effective tax rate for 2004 was 37.4% versus 37.2% in 2003.

Net income in 2003 includes $1.3 million due to an accumulated change in accounting principle for the implementation of Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations” (FAS 143).

2003 versus 2002

Provided below is a comparison of selected operating and financial data for the years 2003 and 2002:

	2003	2002	Percent Change
Total Revenue	$301,377,000	$187,392,000	61%
Income Before Cumulative Effect of Change in Accounting Principle	$ 48,864,000	$ 18,244,000	168%
Net Income	$ 50,189,000	$ 18,244,000	175%
Oil and Natural Gas:			
Revenue	$116,609,000	$ 67,959,000	72%
Operating costs	$ 24,953,000	$ 20,795,000	20%
Average natural gas price (Mcf)	$ 4.87	$ 2.87	70%
Average oil price (Bbl)	$ 26.94	$ 21.54	25%
Natural gas production (Mcf)	20,648,000	18,968,000	9%
Oil production (Bbl)	516,000	473,000	9%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.14	$ 1.04	10%
Depreciation, depletion and amortization (includes $346,000 write off of interest in Shenandoah in 2002)	$ 27,343,000	$ 23,338,000	17%
Gas Gathering and Processing:			
Revenue	$ 606,000	$ 357,000	70%
Operating costs	$ 349,000	$ 396,000	(12)%
Depreciation	$ 176,000	$ 105,000	68%
Gas gathered—MMBtu/day	16,413	9,474	73%
Gas processed—MMBtu/day	92	94	(2)%
Drilling:			
Revenue	$183,146,000	$118,173,000	55%
Operating costs	$138,762,000	$ 91,338,000	52%
Percentage of revenue from daywork contracts	98%	91%	8%
Average number of rigs in use	62.9	39.1	61%
Average dayrate on daywork contracts	$ 7,808	$ 7,716	1%
Depreciation	$ 23,644,000	$ 14,684,000	61%
General and Administrative Expense	$ 9,222,000	$ 8,712,000	6%
Interest Expense	$ 693,000	$ 973,000	(29%)
Average Interest Rate	2.2%	3.0%	(27%)
Average Long-Term Debt Outstanding	$ 20,722,000	$ 24,771,000	(16%)

Oil and natural gas revenues were up $48.7 million or 72% in 2003 as compared with 2002. Increased oil and natural gas prices accounted for 92% of the increase while increased production volumes accounted for 8% of the increase. Increased production came primarily from our development drilling program.

Oil and natural gas operating cost increased $4.2 million or 20% in 2003 as compared to 2002. Gross production taxes represented 77% of the increase due to higher oil and natural gas revenues. General and administrative cost directly related to the production of our wells represented 17% of the increase as labor costs increased within the segment. Total DD&A on our oil and natural gas properties increased $4.0 million or 17%. Higher production volumes were 46% of the increase and increases in the DD&A rate represented 54% of the increase. The increase in the DD&A rate in 2003 resulted from 12% higher development drilling cost per equivalent Mcf in 2003 versus 2002.

Industry demand for our drilling rigs increased gradually throughout 2003 as natural gas prices increased in 2003 versus 2002 and resulted in higher drilling rig use. Drilling revenues increased $65.0 million or 55% in 2003 versus 2002. In December 2003 we acquired 12 rigs with the acquisition of SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC and those drilling rigs increased our 2003 drilling revenues approximately 3% with the remainder of the increase in drilling revenue coming from increased utilization from our previously owned drilling rigs. Average dayrates increased 1% over 2002.

Drilling operating cost increased $47.4 million or 52%. The 12 rigs acquired in the acquisition of SerDrilco increased our 2003 operating cost by approximately 2%. The increase in operating cost from all our acquired drilling rigs and increased utilization from our previously owned drilling rigs represented the total increase in operating cost. Operating cost per day decreased $82 per day or 1%. Cost directly associated with the drilling of wells decreased $148 per day and another $110 per day decrease came from indirect drilling cost with all components of our indirect cost experiencing small declines on a per day basis. These decreases were partially offset by increases in ad valorem taxes and workers' compensation expense. Approximately 2% of our total drilling revenues in 2003 came from footage and turnkey contracts which had profit margins lower than our daywork contracts. Nine percent of our total drilling revenues came from footage and turnkey contracts in 2002. Contract drilling depreciation increased $9.0 million or 61%. The acquisition of the SerDrilco rigs increased depreciation $257,000 or 1% with the remainder of the increase coming primarily from the increase in utilization of previously owned drilling rigs.

General and administrative expense increased $510,000 or 6%. General liability insurance increased $149,000, director and officer insurance increased $235,000 and corporate administrative cost increased $94,000 accounting for most of the increase.

Our total interest expense decreased $280,000 or 29%. Average debt outstanding decreased in 2003 representing approximately 45% of the decrease with the remainder attributable to the decrease in average interest rates. Income tax expense increased $19.3 million or 202% primarily due to an increase in income before income taxes. Our effective tax rate for 2002 was 34.4% versus 37.2% in 2003. The impact of higher statutory depletion and other permanent differences reduced by the impact of state income taxes was the cause for the lower effective tax rate in 2002.

Net income in 2003 includes $1.3 million of income due to an accumulated change in accounting principle for the implementation of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. We own oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). The financial statements for the year ended December 31, 2002 have not been restated and the cumulative effect of the change of $1.3 million net of tax ($0.03 per share) is shown as a one-time addition to income in 2003.

Item 7a. *Quantitative and Qualitative Disclosures about Market Risk*

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

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. The price we receive is primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, the prices we received for our oil and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our 2004 production, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $211,800 per month ($2,541,600 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $81,300 per month ($975,600 annualized) change in our pre-tax operating cash flow.

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

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the JPMorgan Chase Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. Historically, we have not used any financial instruments, such as interest rate swaps, to manage our exposure to possible increases in interest rates. However, in February 2005, we entered into an interest rate swap to help manage our exposure to any future interest rate volatility. A detailed explanation of this transaction has been included under hedging in the financial condition portion of Management's Discussion and Analysis of Financial Condition and Results of Operation included above. Based on our average outstanding long-term debt in 2004, a 1% change in the floating rate would reduce our annual pre-tax cash flow by approximately $831,000.

Item 8. ***Financial Statements and Supplementary Data***

Index To Financial Statements
Unit Corporation and Subsidiaries

Management's Report on Internal Control Over Financial Reporting

The management of the company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has excluded Superior Pipeline Company, L.L.C. (Superior) from its assessment of internal control over financial reporting as of December 31, 2004 because it was acquired by the company in a purchase business combination during 2004. Superior is a wholly-owned subsidiary whose total assets and total revenues represent 3% and 6%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004.

The company's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2004. In making this assessment, the company's management used the criteria set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, management has concluded that, as of December 31, 2004, the company's internal control over financial reporting was effective based on those criteria.

The company's independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited our assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2004, as stated in their report which follows.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Unit Corporation:

We have completed an integrated audit of Unit Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements and Financial Statement Schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2), presents fairly, in all material respects the information set forth herein 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 statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements 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.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the requirements of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Internal Control over Financial Reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Superior Pipeline Company, L.L.C. (Superior) from its assessment of internal control over financial reporting as of December 31, 2004 because it was acquired by the Company in a purchase business combination during 2004. We have also excluded Superior from our audit of internal control over financial reporting. Superior is a wholly-owned subsidiary whose total assets and total revenues represent 3% and 6%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 14, 2005

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2004	As of December 31, 2003
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 665	$ 598
Restricted cash	2,571	—
Accounts receivable (less allowance for doubtful accounts of $1,661 and $1,223)	93,180	58,807
Materials and supplies	13,054	8,023
Income tax receivable	—	112
Prepaid expenses and other	9,131	5,202
Total current assets	118,601	72,742
Property and Equipment:		
Drilling equipment	508,845	424,321
Oil and natural gas properties, on the full cost method:		
Proved properties	731,622	528,110
Undeveloped leasehold not being amortized	28,170	17,486
Gas gathering and processing equipment	38,417	6,686
Transportation equipment	13,559	9,828
Other	10,946	7,849
	1,331,559	994,280
Less accumulated depreciation, depletion, amortization and impairment	466,923	385,219
Net property and equipment	864,636	609,061
Goodwill	30,509	23,722
Other Assets	9,390	7,400
Total Assets	$1,023,136	$712,925
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of other liabilities (Note 4)	$ 5,837	$ 7,116
Accounts payable	49,268	32,871
Accrued liabilities	19,851	9,820
Contract advances	2,220	2,004
Total current liabilities	77,176	51,811
Long-Term Debt (Note 4)	95,500	400
Other Long-Term Liabilities (Note 4)	37,725	17,893
Deferred Income Taxes (Note 5)	204,466	127,053
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 75,000,000 shares authorized, 45,745,399 and 45,592,012 shares issued, respectively	9,149	9,117
Capital in excess of par value	310,132	307,938
Retained earnings	288,988	198,713
Total shareholders' equity	608,269	515,768
Total Liabilities and Shareholders' Equity	$1,023,136	$712,925

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

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2004	2003	2002
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$298,204	$183,146	$118,173
Oil and natural gas	185,017	116,609	67,959
Gas gathering and processing	29,717	606	357
Other	6,265	1,016	903
Total revenues	519,203	301,377	187,392
Expenses:			
Contract drilling:			
Operating costs	210,912	138,762	91,338
Depreciation	33,659	23,644	14,684
Oil and natural gas:			
Operating costs	41,303	24,953	20,795
Depreciation, depletion, amortization and impairment	47,517	27,343	23,338
Gas gathering and processing:			
Operating costs	27,018	349	396
Depreciation	982	176	105
General and administrative	11,987	9,222	8,712
Interest	2,695	693	973
Total expenses	376,073	225,142	160,341
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	143,130	76,235	27,051
Income Tax Expense:			
Current	4,866	—	(3,469)
Deferred	48,592	28,324	12,758
Total income taxes	53,458	28,324	9,289
Equity in Earnings of Unconsolidated Investments, (Net of Income Tax of $372, $563 and $263, in 2004, 2003 and 2002, respectively)	603	953	482
Income Before Cumulative Effect of Change in Accounting Principle	90,275	48,864	18,244
Cumulative Effect of Change in Accounting Principle (Net of Income Tax of $811)	—	1,325	—
Net Income	$ 90,275	$ 50,189	$ 18,244
Basic Earnings Per Common Share:			
Income before cumulative effect of change in accounting principle	$ 1.97	$ 1.12	$ 0.47
Cumulative effect of change in accounting principle net of income tax	—	0.03	—
Net income	$ 1.97	$ 1.15	$ 0.47
Diluted Earnings Per Common Share:			
Income before cumulative effect of change in accounting principle	$ 1.97	$ 1.12	$ 0.47
Cumulative effect of change in accounting principle net of income tax	—	0.03	—
Net income	$ 1.97	$ 1.15	$ 0.47

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

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2002, 2003 and 2004

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2002	$7,201	$141,977	$130,280	$ —	$(296)	$279,162
Net Income	—	—	18,244	—	—	18,244
Activity in employee compensation plans (113,133 shares)	23	1,156	—	—	296	1,475
Issuance of stock for acquisition (7,220,000 shares)	1,444	121,047	—	—	—	122,491
Other comprehensive income (net of tax of $15 and $15):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	—	25	—	25
Adjustment reclassification—derivative settlements	—	—	—	(25)	—	(25)
Balances, December 31, 2002	8,668	264,180	148,524	—	—	421,372
Net Income	—	—	50,189	—	—	50,189
Activity in employee compensation plans (252,612 shares)	49	2,018	—	—	—	2,067
Issuance of 2,000,000 shares of common stock)	400	41,740	—	—	—	42,140
Other comprehensive income (net of tax of $3 and $3):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	—	(4)	—	(4)
Adjustment reclasification—derivative settlements	—	—	—	4	—	4
Balances, December 31, 2003	9,117	307,938	198,713	—	—	515,768
Net Income	—	—	90,275	—	—	90,275
Activity in employee compensation plans (159,907 shares)	32	2,194	—	—	—	2,226
Other comprehensive income (net of tax of $1,345 and $1,345):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	—	(2,195)	—	(2,195)
Adjustment reclassification—derivative settlements	—	—	—	2,195	—	2,195
Balances, December 31, 2004	$9,149	$310,132	$288,988	$ —	$ —	$608,269

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,		
	2004	2003	2002
		(In thousands)	
Cash Flows From Operating Activities:			
Net Income	$ 90,275	$ 50,189	$ 18,244
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization and impairment	83,025	51,783	38,657
Equity in net earnings of unconsolidated investments	(976)	(1,516)	(745)
Loss (gain) on disposition of assets	(4,386)	51	(69)
Employee stock compensation plans	1,632	1,415	1,165
Bad debt expense	400	645	603
Plugging liability—cumulative effect—net of accretion	860	(1,624)	—
Gas balancing adjustment	(111)	—	—
Deferred tax expense	48,964	28,887	13,021
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(14,579)	(25,540)	(43)
Cost of uncompleted drilling contracts	86	—	—
Materials and supplies	(5,031)	771	(3,436)
Prepaid expenses and other	(1,324)	4,240	2,365
Accounts payable	(1,380)	6,148	1,784
Accrued liabilities	5,539	4,286	(350)
Contract advances	216	1,977	(213)
Other liabilities	—	—	(436)
Net cash provided by operating activities	203,210	121,712	70,547
Cash Flows From Investing Activities:			
Capital expenditures	(165,950)	(96,162)	(70,725)
Producing property and other acquisitions	(148,076)	(35,000)	(4,500)
Proceeds from disposition of property and equipment	9,975	1,625	1,949
(Acquisition) disposition of other assets	2,079	(2,562)	540
Net cash used in investing activities	(301,972)	(132,099)	(72,736)
Cash Flows From Financing Activities:			
Borrowings under line of credit	211,200	65,200	36,700
Payments under line of credit	(116,100)	(95,300)	(36,200)
Net payments on notes payable and other long-term debt	(2,100)	(1,105)	(1,161)
Proceeds from exercise of stock options	486	452	413
Proceeds from sale of common stock	—	42,140	—
Book overdrafts (Note 1)	5,343	(899)	2,543
Net cash provided by financing activities	98,829	10,488	2,295
Net Increase in Cash and Cash Equivalents	67	101	106
Cash and Cash Equivalents, Beginning of Year	598	497	391
Cash and Cash Equivalents, End of Year	$ 665	$ 598	$ 497
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Interest	$ 2,520	$ 660	$ 1,053
Income taxes	$ 4,787	$ (3,495)	$ (4,585)

See Note 2 for non-cash investing activities.

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

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its 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.

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to current year presentation.

Nature of Business. Unit is engaged in the land contract drilling of natural gas and oil wells, the exploration, development, acquisition and production of oil and natural gas properties and the gathering and processing of natural gas. Unit's current contract drilling operations are focused primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and the Rocky Mountain regions. Unit's primary exploration and production operations are also conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of its contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas. At December 31, 2004, Unit had an interest in a total of 5,885 wells and served as operator of 1,019 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 2004, all of Unit's 100 rigs owned during 2004 performed contract drilling services. Our gas gathering and processing operations consists of one natural gas treatment plant, three processing plants, 32 active gathering systems and 440 miles of pipeline. Gas gathering and processing operations are performed in western Oklahoma, the Texas Panhandle and Louisiana.

Drilling Contracts. Unit recognizes revenues and expenses generated from "daywork" drilling contracts as the services are performed, since the Company does not bear the risk of completion of the well. Under "footage" and "turnkey" contracts, Unit bears the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The duration of all three types of contracts range typically from 20 to 90 days, but some of our daywork contracts in the Rocky Mountains can range up to one year. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

Cash Equivalents and Book Overdrafts. Unit includes as cash equivalents, certificates of deposits and all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued prior to the end of the period, but not presented to Unit's bank for payment prior to the end of the period. At December 31, 2004 and 2003, book overdrafts of $8.0 million and $2.7 million have been included in accounts payable.

Property and Equipment. Drilling equipment, natural gas gathering and processing equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements 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% of the active rate when the equipment is idle. Unit uses the composite method of depreciation for drill pipe and collars and calculates the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

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

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

Goodwill. Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company, CDC Drilling Company, SerDrilco Incorporated and Sauer Drilling Company over the fair value of the net assets acquired. For goodwill and intangible assets recorded in the financial statements, an impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to the drilling segment. The 2003 increase in the carrying amount of goodwill of $10.9 million came from the goodwill acquired in the acquisition of SerDrilco Incorporated. In 2004 the increase in the carrying amount of goodwill of $6.8 million came from the goodwill acquired in the acquisition of Sauer Drilling Company of $4.9 million and from the additional goodwill recorded from the SerDrilco Incorporated acquisition of $1.9 million for the 2004 earn-out as provided for in the sales agreement. Both acquisitions are more fully discussed in Note 2. Goodwill of $10.6 million is expected to be deductible for tax purposes.

Oil and Natural Gas Operations. Unit accounts for its oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the Securities and Exchange Commission ("SEC"). Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. All costs associated with acquisition, exploration and development of oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized. 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 $1.41, $1.14 and $1.04 per Mcfe in 2004, 2003 and 2002, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Unit's unproved properties totaling $28.2 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 Supplemental Information, such estimates are imprecise.

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

Unit's contract drilling subsidiary provides drilling services for its exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. During 2004, the contract drilling subsidiary drilled 35 wells for our exploration and production subsidiary. As required by the Securities and Exchange Commission, the profit received by our contract drilling segment of $3.7 million, $1.9 million and $0.8 million during 2004, 2003 and 2002, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in 11 oil and natural gas limited partnerships sold privately and publicly. Some of Unit's officers, directors and employees own the interests in most of these partnerships. Unit shares partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The partnerships also reimburse Unit for certain administrative costs incurred on behalf of the partnerships.

Income Taxes. Measurement of current and deferred income tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

Natural Gas Balancing. Unit uses the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Unit estimates its December 31, 2004 balancing position to be approximately 1.7 Bcf on under-produced properties and approximately 2.3 Bcf on over-produced properties. Unit has recorded a receivable of $221,000 on certain wells where we estimated that insufficient reserves are available for Unit to recover the under-production from future production volumes. Unit has also recorded a liability of $1.1 million on certain properties where we believe there are insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Unit's policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which Unit has imbalances are not material.

Employee and Director Stock Based Compensation. Unit's stock-based compensation plans, which are explained more fully in Note 6, are accounted for under the recognition and measurement principles of APB Opinion 25 "Accounting for Stock Issued to Employees," and related interpretations. 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 2004, 2003 and 2002 no compensation expense has been recognized. Compensation expense included in reported net income is Unit's matching 401(k) contribution which was made in Unit common stock. The following table illustrates the effect on net income and earnings per share if Unit had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	2004	2003	2002
	(In thousands except per share amounts)		
Net Income, as Reported	$90,275	$50,189	$18,244
Add Stock Based Employee Compensation Expense Included in Reported Net Income—Net of Tax	1,026	858	669
Less Total Stock Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(2,760)	(2,114)	(1,488)
Pro Forma Net Income	$88,541	$48,933	$17,425
Basic Earnings per Share:			
As reported	$ 1.97	$ 1.15	$ 0.47
Pro forma	$ 1.94	$ 1.12	$ 0.45
Diluted Earnings per Share:			
As reported	$ 1.97	$ 1.15	$ 0.47
Pro forma	$ 1.93	$ 1.12	$ 0.45

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility in 2004, 2003 and 2002 was 0.51, 0.52 and 0.53, respectively, based on previous stock performance. Dividend yield was estimated to remain at zero with a risk free interest rate of 4.40% in 2004 and 4.24% in 2003 and 2002. 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 2004 and 2003 under the Stock Option Plan were $2.9 million and $1.6 million, respectively. Under the Non-Employee Directors' Stock Option Plan the aggregate fair value of options granted during 2004 was $430,000 and was $262,000 in 2003 and 2002.

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 $18.8 million and $8.0 million for employer group health insurance and worker's compensation at December 31, 2004 and 2003, respectively. Our insurance policies contain deductibles or retentions per occurrence ranging from $200,000 for general liability to $1.0 million for drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain claims. There is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco, Unit continued to use SerDrilco's ERISA governed occupational injury benefit plan to cover the SerDrilco employees in lieu of covering them under an insured Texas workers' compensation plan.

Treasury Stock. On August 30, 2001, Unit's Board of Directors authorized the purchase of up to one million shares of Unit's common stock. The timing of stock purchases are made at the discretion of management. No treasury stock was owned by Unit at December 31, 2004, 2003 and 2002.

Financial Instruments and Concentrations of Credit Risk. Financial instruments, which potentially subject Unit to concentrations of credit risk, consist primarily of trade receivables with a variety of national and international oil and natural gas companies. Unit does not generally require collateral related to receivables. Such credit risk is considered by management to be limited due to the large number of customers comprising Unit's customer base. During 2004, Chesapeake Operating, Inc. was our largest drilling customer and provided 11% of our total contract drilling revenues. Purchases by Eagle Energy Partners I, L.P. accounted for approximately 25% of Unit's oil and natural gas revenues in 2004 while purchases by Cinergy Marketing and Trading LP accounted for approximately 11% of Unit's oil and natural gas revenues. Prior to August 2, 2004 Unit owned 16.7% interest in Eagle Energy Partners I LP, whose purchases accounted for 25% of Unit's oil and natural gas revenues in 2004. In addition, at December 31, 2004, Unit had a concentration of cash of $8.8 million and $6.9 million with two banks and at December 31, 2003 had a concentration of cash of $3.5 million with one bank.

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

Unit periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the- counter swaps and basic hedges with major energy derivative product specialists. Initial adoption of this standard was not material.

On April 30, 2002, Unit entered into a natural gas collar contract for 10,000 MMBtu's of production per day and covering the periods of April through October 2002. The collar had a floor price of $3.00 and a ceiling price of $3.98. During the year of 2002, the natural gas hedging transactions increased natural gas revenues by $40,300. At December 31, 2002, Unit was not holding any natural gas or oil derivative contracts. These hedges were cash flow hedges and there was no material amount of ineffectiveness.

During the first quarter of 2003, Unit entered into two collar contracts. Each collar contract was for 10,000 MMBtu's of production per day and covered the periods of April through September 2003. One contract had a floor price of $4.00 and a ceiling price of $5.75 and the other contract had a floor price of $4.50 and a ceiling price of $6.02. Unit also entered into two oil collar contracts. Each contract was for 5,000 barrels of production per month and covered the periods of May through December 2003. One contract had a floor price of $25.00 and a ceiling price of $32.20 and the other contract had a floor price of $26.00 and a ceiling price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. During the year 2003, the collar contracts decreased natural gas revenues by $6,000 and oil revenues by $5,000. We did not have any hedging transactions outstanding at December 31, 2003.

During the first and second quarters of 2004, we entered into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covered the period of April through October of 2004 and had a floor of $4.50 and a ceiling of $6.76. The other contract covered the period of May through October of 2004 and had a floor of $5.00 and a ceiling of $7.00. We also entered into an oil hedge covering 1,000 barrels per day of oil production. The transaction covered the periods of February through December of 2004 and had an average price of $31.40. These hedges were cash flow hedges and there was no material amount of ineffectiveness. The natural gas collar contracts increased natural gas revenues by $48,000 during 2004. Oil revenues were reduced by $3.6 million in 2004 due to the settlement of the oil hedge. We did not have any hedging transactions outstanding at December 31, 2004.

In January 2005, we enter into two natural gas collar contracts. Each collar contract was for 10,000 MMBtu's of production per day. One contract covered the period of April through October of 2005 and had a floor of $5.50 and a ceiling of $7.19. The other contract covered the period of April through October of 2005 and had a floor of $5.50 and a ceiling of $7.30. These hedges are cash flow hedges and there is no material amount of ineffectiveness.

In February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. The contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 2008. This period coincides with the remaining length of our current credit facility. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge.

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

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

In September 2004, the staff of the SEC issued Staff Accounting Bulletin No. 106 (SAB 106) to express the staff's views regarding application of FAS 143, "Accounting for Asset Retirement Obligations," by oil and natural gas producing companies following the full cost accounting method. SAB 106 addressed the computation of the full cost ceiling test to avoid double-counting asset retirement costs, the disclosures a full cost accounting company is expected to make regarding the impacts of FAS 143, and the amortization of estimated dismantlement and abandonment costs that are expected to result from future development activities. The accounting and disclosures described in SAB 106 have been adopted by the Company as of the fourth quarter of 2004 and did not have a material impact on the financial position of the Company, or on its results of operations.

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. The Company has not determined the impact, if any, that this statement will have on its results of operations or its financial condition.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended Accounting Principles Board (APB) Opinion No. 29, "Accounting for Nonmonetary Transactions." FAS 153 requires that nonmonetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. The Company does not expect this statement to have a material impact on it results of operations or its financial condition.

In December 2004, the FASB issued FAS 123R, which requires that compensation cost relating to share-based payments be recognized in the company's financial statements. The company currently accounts for those payments under recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. The company is preparing to implement this standard effective July 1, 2005. Although the transition method to be used to adopt the standard has not been selected, see Employee and Director Stock Based Compensation section of Note 1 for the effect on net income and earnings per share for the years 2002 through 2004 if the company had applied the fair value recognition provision of FAS 123 to stock based employee compensation.

On January 1, 2003 the company adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. The company owns oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). The company does not have any assets restricted for the purpose of settling the plugging liabilities. Pro forma amounts assuming retroactive application of change in accounting principle for 2002 make net income $48.1 million with basic earnings per share $0.47 and diluted earnings per share $0.46.

The following table shows the activity for the year ending December 31, 2004 relating to the company's retirement obligation for plugging liability:

	Short-Term Plugging Liability	Long-Term Plugging Liability
	(In Thousands)	
Plugging Liability January 1, 2004	$303	$11,691
Accretion of Discount	6	854
Liability Incurred in the Period	—	6,524
Liability Settled in the Period	(62)	(95)
Liability Sold	(21)	(63)
Reclassification of Liability From Long- to Short-Term	—	—
Revision of Estimate	—	(2)
Plugging Liability December 31, 2004	$226	$18,909

NOTE 2—ACQUISITIONS

On July 30, 2004, the company's wholly-owned subsidiary, Unit Drilling Company, acquired Sauer Drilling Company, a Casper-based drilling company. The acquisition was for $40.3 million in cash including working capital of $5.3 million. This acquisition includes nine drilling rigs, a fleet of trucks, and an equipment and repair yard with associated inventory, located in Casper, Wyoming. The rigs range from 500 horsepower to 1,000 horsepower with depth capacities rated from 5,000 feet to 16,000 feet. The fleet of trucks consists of four vacuum trucks and 11 rig-up trucks used to move the rigs to new drilling locations. The trucks also have the capacity to move third-party rigs. The equipment yard, located in Casper, Wyoming, will continue to provide service space for the nine newly acquired rigs and trucks as well as for the company's existing Rocky Mountain rig fleet. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004.

The $40.3 million paid for Sauer was allocated as follows (in thousands):

Drilling Rigs Including Tubulars	$26,428
Spare Drilling Equipment	1,498
Trucking Fleet	1,433
Land and Buildings	510
Other Vehicles	182
Working Capital	5,322
Goodwill Recognized	4,898
Total consideration	$40,271

The amount paid was determined through arms-length negotiations between the parties.

On July 29, 2004, the company completed its acquisition of the 60% of Superior Pipeline Company L.L.C. ("Superior") it did not already own for $19.8 million, resulting in the company's 100% ownership of Superior. Before this acquisition, the company's 40% interest in the operations of Superior was shown as equity in earnings of unconsolidated investments, net of income tax. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas and operates one natural gas treatment plant, two processing plants, 12 active gathering systems and 400 miles of pipeline. Superior operates in western Oklahoma and the Texas Panhandle and has been in business since 1996. This acquisition will increase the company's ability to gather and market its natural gas (as well as third party natural gas) and construct or acquire existing natural gas gathering and processing facilities. The results of operations for this acquired company are included in the statement of income for the period after July 31, 2004 and intercompany revenue from services and purchases of production between the company's subsidiaries has been eliminated.

The $19.8 million paid for Superior was allocated as follows (in thousands):

Gas Gathering and Processing Facilities	$20,886
Other Long-Term Liabilities	(1,080)
Working Capital	(6)
Total consideration	$19,800

The amount paid was determined through arms-length negotiations between the parties.

On May 4, 2004, the company acquired two drilling rigs and related equipment for $5.5 million. The drilling rigs are rated at 850 and 1,000 horsepower, respectively, with depth capacities from 12,000 to 15,000 feet. The company refurbished the rigs for approximately $4.0 million. One drilling rig was placed into service at the beginning of August 2004 and the other rig was placed into service in the middle of September 2004. Both drilling rigs are working in the area covered by the Rocky Mountain division.

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

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

Working Capital	$ 97,943
Undeveloped Oil and Natural Gas Properties	6,321
Proved Oil and Natural Gas Properties	107,591
Property and Equipment—Other	382
Other Assets	1,445
Other Long-Term Liabilities	(5,271)
Deferred Income Taxes	(26,291)
Total consideration	$182,120

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

At the closing of this acquisition, $5.5 million, otherwise payable to the shareholders of PetroCorp Incorporated, was transferred to an escrow account to reserve for certain liabilities and related costs that may be incurred by PetroCorp Incorporated after the closing of the acquisition. As of December 31, 2004, $2.6 million is in escrow and is reflected as restricted cash.

Unaudited summary pro forma results of operations for the company, reflecting the PetroCorp, Sauer Drilling Company and Superior Pipeline Company LLC acquisitions as if they occurred at January 1, 2003 are as follows:

	Year Ended December 31,	
	2004	2003
	(In thousands except per share amounts)	
Revenues	$569,915	$406,663
Income before cumulative effect of change in accounting principle	$ 92,757	$ 57,482
Net Income	$ 92,757	$ 55,838
Basic Earnings per Share:		
Income before cumulative effect of change in accounting principle	$ 2.03	$ 1.32
Net income	$ 2.03	$ 1.28
Diluted Earnings per Share:		
Income before cumulative effect in change in accounting principle	$ 2.02	$ 1.31
Net income	$ 2.02	$ 1.28

The pro forma results of operations are not necessarily indicative of the actual results of operations that would have occurred for the respective periods or of the results which may occur in the future.

On December 8, 2003, Unit acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10.0 million for each of the three years following the acquisition. An additional $1.9 million was added to goodwill for the liability associated with the 2004 earn-out. The assets of SerDrilco Incorporated included 12 drilling rigs, spare drilling equipment, a fleet of 12 larger trucks and trailers, various other vehicles and a district office and equipment yard in and near Borger, Texas. The results of operations for the acquired entity are included in the statement of operations for the period beginning December 8, 2003 and continuing through December 31, 2004.

Total consideration given in the acquisition was determined based on the depth capacity of the rigs, the working condition of the rigs and the ability of the rigs to enhance Unit's ability to provide services and equipment required by our customers on a timely basis within the Anadarko Basin of Western Oklahoma and the Texas Panhandle. Unit acquired SerDrilco Incorporated's tax basis in the property acquired, so a deferred tax liability and goodwill of $10.9 million was recognized in the recording of the acquisition. The allocation of the total consideration paid and goodwill recognized for the acquisition prior to the subsequent earn-out provision calculations is as follows (in thousands):

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

On August 15, 2002, Unit completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company ("Cactus Acquisition"). Both of these acquisitions were stock purchase transactions. Unit issued 6.8 million shares of common stock and paid $3.8 million for all the outstanding shares of CREC Rig Equipment Company and issued 400,252 shares of common stock and paid $686,947 for all the outstanding shares of CDC Drilling Company. The assets of the acquired companies included 20 drilling rigs, spare drilling equipment and vehicles. What we paid in both transactions was determined through arms-length negotiations between the parties and only the cash portion of the transaction appears in the investing and financing activities of Unit's Consolidated Statement of Cash Flows. The results of operations for the acquired entities are included in the statement of operations for the period beginning August 15, 2002 and continuing through December 31, 2004.

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

Calculation of Consideration Paid:	
Unit Corporation common stock (7,220,000 shares at $16.96556 per share)	$122,491
Cash	4,500
Total consideration	$126,991
Allocation of Total Consideration Paid:	
Drilling rigs	$112,994
Spare drilling equipment	3,500
Vehicles	636
Deferred tax asset	2,155
Goodwill	7,706
Total consideration	$126,991

Unaudited summary pro forma results of operations for Unit, reflecting the Cactus Acquisition as if it had occurred at the beginning of the year ended December 31, 2002 are as follows:

	Year Ended December 31, 2002
	(In thousands except per share amounts)
Revenues	$215,805
Net Income	$ 15,320
Net Income per Common Share (Diluted)	$ 0.34

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

NOTE 3—EARNINGS PER SHARE

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

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Year Ended December 31, 2004:			
Basic earnings per common share	$90,275	45,717	$1.97
Effect of dilutive stock options		217	
Diluted earnings per common share	$90,275	45,934	$1.97
For the Year Ended December 31, 2003:			
Basic earnings per common share:			
Income before cumulative effect of change in accounting principle	$48,864	43,616	$1.12
Cumulative effect of change in accounting principle net of income tax	1,325	43,616	0.03
Net Income	$50,189	43,616	$1.15
Diluted earnings per Common share:			
Weighted average number of common shares used in basic earnings per common share		43,616	
Effect of dilutive stock options		157	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		43,773	
Income before cumulative effect of change in accounting principle	$48,864	43,773	$1.12
Cumulative effect of change in accounting principle net of income tax	1,325	43,773	0.03
Net Income	$50,189	43,773	$1.15
For the Year Ended December 31, 2002:			
Basic earnings per common share	$18,244	38,844	$0.47
Effect of dilutive stock options		268	
Diluted earnings per common share	$18,244	39,112	$0.47

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

	2004	2003	2002
Options	127,500	137,850	198,500
Average Exercise Price	$ 37.83	$ 22.52	$ 19.01

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

Long-term debt consisted of the following as of December 31, 2004 and 2003:

	2004	2003
	(In thousands)	
Revolving Credit Loan, with Interest at December 31, 2004 and 2003 of 3.1% and 4.0%, Respectively	$95,500	$400
Less Current Portion	—	—
Total Long-Term Debt	$95,500	$400

On January 30, 2004, in conjunction with the company's acquisition of PetroCorp Incorporated, the company replaced its credit agreement with a revolving $150.0 million credit facility having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount and the company has elected to have the full $150.0 million available as the commitment amount. The company pays a commitment fee of .375 of 1% for any unused portion of the commitment amount. The company incurred origination, agency and syndication fees of $515,000 at the inception of the new agreement, $40,000 of which will be paid annually and the remainder of the fees will be amortized over the four year life of the loan.

The borrowing base under the current credit facility is subject to re-determination on May 10 and November 10 of each year. Each re-determination is based primarily on the sum of a percentage of the discounted future value of the company's oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of the company's drilling rig fleet, limited to $20.0 million, is added to the borrowing base. The agreement also allows for one requested special re-determination of the borrowing base (by either the lender or the company) between each scheduled re-determination date if conditions warrant such a request.

At the company's election, any part of the outstanding debt may be fixed at a LIBOR Rate for a 30, 60, 90 or 180 day term. During any LIBOR Rate funding period the outstanding principal balance of the note to which such LIBOR Rate option applies may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR Rate is computed at the LIBOR Base Rate applicable for the interest period plus 1.00% to 1.50% depending on the level of debt as a percentage of the total loan value and payable at the end of each term or every 90 days whichever is less. Borrowings not under the LIBOR Rate bear interest at the JPMorgan Chase Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty.

The credit agreement includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain limited exceptions, and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of the company's banks.

The credit agreement also requires that the company have at the end of each quarter:

- consolidated net worth of at least $350.0 million,
- a current ratio (as defined in the credit agreement) of not less than 1 to 1, and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

On December 31, 2004, the company was in compliance with the covenants of its credit agreement.

Other long-term liabilities consisted of the following as of December 31, 2004 and 2003:

	2004	2003
	(In thousands)	
Separation Benefit Plan	$ 2,821	$ 2,545
Deferred Compensation Plan	2,111	1,829
Retirement Agreement	1,240	1,349
Workers' Compensation	17,175	6,101
Gas Balancing Liability	1,080	1,191
Plugging Liability	19,135	11,994
	43,562	25,009
Less Current Portion	5,837	7,116
Total Other Long-Term Liabilities	$37,725	$17,893

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities from 2005 through 2009 are $5.8 million, $4.6 million, $1.8 million, $97.8 million and $1.4 million. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2004 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:

	2004	2003	2002
		(In thousands)	
Income Tax Expense Computed by Applying the Statutory Rate	$50,437	$27,213	$ 9,739
State Income Tax, Net of Federal Benefit	4,323	2,333	834
Statutory Depletion and Other	(930)	(659)	(1,021)
Income tax expense	$53,830	$28,887	$ 9,552

Deferred tax assets and liabilities are comprised of the following at December 31, 2004 and 2003:

	2004	2003
	(In thousands)	
Deferred Tax Assets:		
Allowance for losses and nondeductible accruals	$ 15,228	$ 9,972
Net operating loss carryforward	7,392	20,745
Statutory depletion carryforward	4,786	4,476
Alternative minimum tax credit Carryforward	6,410	395
	33,816	35,588
Deferred Tax Liability:		
Depreciation, depletion and Amortization	(233,058)	(159,990)
Net deferred tax liability	(199,242)	(124,402)
Current Deferred Tax Asset	5,224	2,651
Non-Current—Deferred Tax Liability	$(204,466)	$(127,053)

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

At December 31, 2004, Unit has an excess statutory depletion carryforward of approximately $12.6 million, which may be carried forward indefinitely and is available to reduce future taxable income, subject to statutory limitations. At December 31, 2004, Unit has net operating loss carryforwards of approximately $19.5 million which expire from 2006 to 2023.

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. No shares were issued under the Plan in 2002, 2003 and 2004.

Unit also has a Stock Option Plan (the "Option Plan"), which provides for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The Option Plan permits the issuance of qualified or nonqualified stock options. Options granted typically become exercisable at the rate of 20% per year one year after being granted and expire after 10 years from the original grant date. The exercise price for options granted under this plan is the fair market value of the common stock on the date of the grant.

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2002	532,100	$ 8.09
Granted	160,000	19.03
Exercised	(59,400)	5.67
Outstanding at December 31, 2002	632,700	11.08
Granted	116,850	22.89
Exercised	(202,900)	5.94
Cancelled	(9,900)	15.41
Outstanding at December 31, 2003	536,750	15.52
Granted	134,500	37.23
Exercised	(101,800)	7.84
Cancelled	(15,700)	18.66
Outstanding at December 31, 2004	553,750	$22.11

	Outstanding Options at December 31, 2004		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$3.75	42,100	4.0 years	$ 3.75
$8.75	28,000	2.0 years	$ 8.75
$14.06 – $19.04	236,300	7.1 years	$18.00
$21.50 – $26.28	119,850	9.0 years	$23.08
$37.72 – $37.83	127,500	10.0 years	$37.83

	Exercisable Options At December 31, 2004	
Exercise Prices	Number of Shares	Weighted Average Exercise Price
$3.75	42,100	$ 3.75
$8.75	28,000	$ 8.75
$14.06 – $19.04	133,500	$17.60
$21.50 – $26.28	22,570	$22.89
$37.72 – $37.83	—	$ —

Options for 226,170, 256,300 and 355,100 shares were exercisable with weighted average exercise prices of $14.46, $5.32 and $7.28 at December 31, 2004, 2003 and 2002, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Old Plan") and in February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (the "Directors' Plan"). Under the Directors' Plan, which replaced the Old Plan, an aggregate of 300,000 shares of Unit's common stock may be issued upon exercise of the stock options. Under the Old Plan, on the first business day following each annual meeting of stockholders of Unit, each person who was then a member of the Board of Directors of Unit and who was not then an employee of Unit or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. Under the Directors' Plan, commencing with the year 2000 annual meeting, the amount granted has been increased to 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. No stock options may be exercised during the first six months of its term except in case of death and no stock options are exercisable after 10 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, 2002	75,500	$ 9.58
Granted	21,000	20.10
Exercised	(2,500)	1.75
Outstanding at December 31, 2002	94,000	12.14
Granted	21,000	20.46
Exercised	(34,500)	7.73
Outstanding at December 31, 2003	80,500	16.19
Granted	24,500	28.23
Exercised	(11,000)	8.24
Outstanding at December 31, 2004	94,000	$20.27

	Outstanding and Exercisable Options at December 31, 2004		
Exercise Prices	**Number of Shares**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**
$ 6.87 – $ 9.00	10,000	3.3 years	$ 7.42
$12.19 – $17.54	17,500	6.1 years	$16.47
$20.10 – $20.46	42,000	7.8 years	$20.28
$28.23	24,500	9.3 years	$28.23

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. Unit made discretionary contributions under the plan of 56,152, 61,175 and 87,452 shares of common stock and recognized expense of $1.6 million, $1.4 million and $1.1 million in 2004, 2003 and 2002, respectively.

Unit provides a salary deferral plan ("Deferral Plan") which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. Funds set aside in a trust to satisfy Unit's obligation under the Deferral Plan at December 31, 2004, 2003 and 2002 totaled $2.1 million, $1.8 million and $1.4 million, 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 four 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 $707,000, $707,000 and $619,000 in 2004, 2003 and 2002, respectively, for benefits associated with anticipated payments from both separation plans.

Unit has entered into key employee change of control contracts with five of its current executive officers. These severance contracts have an initial three-year term that is automatically extended for one year upon each anniversary, unless a notice not to extend is given by Unit. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive's terms and conditions for employment (including position, work location, compensation and benefits) will not be adversely changed during the three-year period after a change of control. If the executive's employment is terminated (other than for cause, death or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and upon certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the

Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 7—TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company serves as the general partner of 11 oil and gas limited partnerships. Four were formed for investment by third parties and seven (the employee partnerships) were formed to allow employees of Unit and its subsidiaries and directors of Unit to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984, 1985 and 1986. An additional third party partnership, the 1979 Oil and Gas Limited Partnership was dissolved on July 1, 2003. Employee partnerships have been formed for each year beginning with 1984. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount ($36,000 for both 2005 and 2004 and $22,680 for 2003) and to the directors of Unit.

The employee partnerships formed in 1984 through 1990 were consolidated into a single consolidating partnership in 1993 and the employee partnerships formed in 1991 through 1999 were also consolidated into the consolidating partnership in 2002. The consolidation of the 1991 through the 1999 employee partnerships at the end of last year was done by the general partners under the authority contained in the respective partnership agreements and did not involve any vote, consent or approval by the limited partners. The employee partnerships have each had a set percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells we drill or acquire for our own account during the particular year for which the partnership was formed. The total interest the employees have in our oil and natural gas wells by participating in these partnerships does not exceed one percent.

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

	2004	2003	2002
	(In thousands)		
Contract Drilling	$262	$428	$209
Well Supervision and Other Fees	$259	$236	$510
General and Administrative Expense Reimbursement	$225	$209	$210

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

In July 2004, Unit completed its acquisition of the 60% of Superior Pipeline Company LLC ("Superior") it did not already own for $19.8 million. Superior is a mid-stream company engaged primarily in the purchasing, gathering, processing and treating of natural gas. Prior to the acquisition Unit owned a 40% equity interest in Superior. The investment, including Unit's share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and was reported in other assets in Unit's consolidated balance sheet. During 2004, Superior Pipeline Company LLC purchased $1.8 million of our natural gas production and paid $53,000 for our natural gas liquids.

On August 2, 2004, Unit completed the sale of its 16.7% limited partner interest in Eagle Energy Partners I, L.P. Eagle is engaged in the purchase and sale of natural gas, electricity (or similar electricity based products), future commodities, and the performance of scheduling and nomination services for both energy related commodities and similar energy management functions. Unit increased its sales to Eagle Energy Partners I LP since it first starting selling natural gas to them in August, 2003. For the period August through December 2003 Eagle has purchased 16% of Unit's oil and natural gas revenues. Total purchases by Eagle Energy Partnership I, L.P., which are competitively marketed, accounted for 55% of Unit's oil and natural gas revenues in 2004.

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% of its value.

The rights become exercisable 10 days after Unit learns that an acquiring person (as defined in the Plan) has acquired 15% 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% 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 10th 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 in Tulsa and Woodward, Oklahoma and Houston and Midland, Texas under the terms of operating leases expiring through January 31, 2010. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $1,167,000, $1,156,000, $773,000, $549,000 and $541,000 in 2005, 2006, 2007, 2008 and 2009, respectively. Total rent expense incurred by the Company was $839,000, $752,000 and $678,000 in 2004, 2003 and 2002, respectively.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, upon the election of a limited partner, that Unit repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. Unit made repurchases of $14,000 in 2004, $106,000 in 2003 and $1,000 in 2002 for such limited partners' interests.

Unit manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to Unit's satisfaction, or agree to assume liability for the remediation of the property.

We have not historically experienced any environmental liability while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the rig is on the location and the cost has been included in the direct cost of drilling the well.

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

NOTE 10—INDUSTRY SEGMENT INFORMATION

Unit has three business segments: Contract Drilling, Oil and Natural Gas and Gas Gathering and Processing, representing its three main business units offering different products and services. The Contract Drilling segment is engaged in the land contract drilling of oil and natural gas wells, the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties and the Gas Gathering and Processing segment is engaged in the purchasing, gathering, processing and treating of natural gas.

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.

	2004	2003	2002
		(In thousands)	
Revenues:			
Contract drilling	$ 309,372	$188,832	$119,014
Elimination of inter-segment revenue	11,168	5,686	841
Contract drilling net of inter-segment revenue	298,204	183,146	118,173
Oil and natural gas	185,017	116,609	67,959
Gas gathering and processing	33,358	1,329	779
Elimination of inter-segment revenue	3,641	723	422
Gas gathering and processing net of inter-segment revenue	29,717	606	357
Other	6,265	1,016	903
Total revenues	$ 519,203	$301,377	$187,392
Operating Income (1):			
Contract drilling	$ 53,633	$ 20,740	$ 12,151
Oil and natural gas	96,197	64,313	23,826
Gas gathering and processing	1,717	81	(144)
Total operating income	151,547	85,134	35,833
General and administrative expense	(11,987)	(9,222)	(8,712)
Interest expense	(2,695)	(693)	(973)
Other income (expense)—net	6,265	1,016	903
Income before income taxes	$ 143,130	$ 76,235	$ 27,051
Identifiable Asset (2):			
Contract drilling	$ 454,393	$364,855	$299,655
Oil and natural gas	512,909	327,172	261,440
Gas gathering and processing	41,250	4,153	1,349
Total identifiable assets	1,008,552	696,180	562,444
Corporate assets	14,584	16,745	15,719
Total assets	$1,023,136	$712,925	$578,163
Capital Expenditures:			
Contract drilling	$ 98,437(3)	$ 71,899(5)	$139,298(7)
Oil and natural gas	215,074(4)	80,883(6)	58,778
Gas gathering and processing	31,785	3,238	75
Other	3,581	702	441
Total capital expenditures	$ 348,877	$156,722	$198,592
Depreciation, Depletion, Amortization and Impairment:			
Contract drilling	$ 33,659	$ 23,644	$ 14,684
Oil and natural gas	47,517	27,343	23,338
Gas gathering and processing	982	176	105
Other	867	620	530
Total depreciation, depletion, amortization and impairment	$ 83,025	$ 51,783	$ 38,657

(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 $4.9 million for goodwill acquired in the Sauer acquisition and $1.9 million for goodwill from the SerDrilco earn-out agreement.

(4) Includes $26.3 million for deferred tax on assets acquired.

(5) Includes $10.9 million for goodwill.

(6) Includes $7.6 million for capitalized cost relating to plugging liability recorded in 2003.

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

NOTE 11—SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2004 and 2003 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year Ended December 31, 2004:				
Revenues	$101,610	$114,028	$143,350	$160,215
Gross profit (1)	$ 27,375	$ 35,313	$ 39,043	$ 49,816
Income before income taxes and cumulative effect of change in accounting principle	$ 24,563	$ 32,222	$ 39,737	$ 46,608
Net income	$ 15,509	$ 20,185	$ 24,647	$ 29,934
Net income per common share:				
Basic	$ 0.34	$ 0.44	$ 0.54	$ 0.65
Diluted	$ 0.34	$ 0.44	$ 0.54	$ 0.65

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year Ended December 31, 2003:				
Revenues	$68,460	$72,498	$77,800	$82,619
Gross profit (1)	$22,517	$20,298	$22,344	$19,975
Income before income taxes and cumulative effect of change in accounting principle	$20,211	$18,332	$20,142	$17,550
Income before cumulative effect of change in accounting principle	$12,659	$11,691	$12,763	$11,751
Net income (2)	$13,984	$11,691	$12,763	$11,751
Earnings before cumulative effect of change in accounting principle per common share:				
Basic	$ 0.29	$ 0.27	$ 0.29	$ 0.27
Diluted	$ 0.29	$ 0.27	$ 0.29	$ 0.27
Net income per common share:				
Basic	$ 0.32	$ 0.27	$ 0.29	$ 0.27
Diluted	$ 0.32	$ 0.27	$ 0.29	$ 0.27

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

(2) The net income for the three months ended December 31, 2003 includes a tax benefit of $0.8 million relating primarily to an increase in the estimated amount of statutory depletion carryforward.

NOTE 12—SUBSEQUENT EVENT

On January 5, 2005 Unit acquired a subsidiary of Strata Drilling LLC for $10.5 million in cash. With this acquisition Unit acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major rig components. The two rigs are 1,500 horsepower, diesel electric rigs with the capacity to drill 12,000 to 20,000 feet. One rig is currently operating under contract and the other rig will require approximately $2.0 million in expenditures to complete. The latter rig should be fully operational within 90 days. Both rigs will be in our Rocky Mountain Division.

The preliminary allocation of the total consideration paid for the acquisition is as follows (in thousands):

Rigs	$ 5,712
Spare Drilling Equipment	2,715
Drill Pipe and Collars	932
Goodwill	1,106
Total consideration	$10,465

SUPPLEMENTAL INFORMATION

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

	USA	Canada	Total
		(In thousands)	
2002:			
Capitalized costs:			
Proved properties	$ 448,331	$ 895	$ 449,226
Unproved properties	15,692	332	16,024
	464,023	1,227	465,250
Accumulated depreciation, depletion, amortization and impairment	(218,956)	(520)	(219,476)
Net capitalized costs	$ 245,067	$ 707	$ 245,774
Cost incurred:			
Unproved properties acquired	$ 5,330	$ 152	$ 5,482
Proved properties acquired	13,379	—	13,379
Exploration	6,591	—	6,591
Development	33,319	7	33,326
Total costs incurred	$ 58,619	$ 159	$ 58,778
2003:			
Capitalized costs:			
Proved properties	$ 527,196	$ 914	$ 528,110
Unproved properties	17,149	337	17,486
	544,345	1,251	545,596
Accumulated depreciation, depletion, amortization and impairment	(240,047)	(540)	(240,587)
Net capitalized costs	$ 304,298	$ 711	$ 305,009
Cost incurred:			
Unproved properties acquired	$ 8,611	$ 19	$ 8,630
Proved properties acquired	2,557	—	2,557
Exploration	7,071	—	7,071
Development (1)	62,620	5	62,625
Total costs incurred	$ 80,859	$ 24	$ 80,883
2004:			
Capitalized costs:			
Proved properties	$ 730,629	$ 993	$ 731,622
Unproved properties	27,842	328	28,170
	758,471	1,321	759,792
Accumulated depreciation, depletion, amortization and impairment	(287,160)	(636)	(287,796)
Net capitalized costs	$ 471,311	$ 685	$ 471,996
Cost incurred:			
Unproved properties acquired	$ 17,165	$ 5	$ 17,170
Proved properties acquired	108,191	—	108,191
Exploration	8,068	—	8,068
Development	81,580	65	81,645
Total costs incurred	$ 215,004	$ 70	$ 215,074

(1) Includes $7.0 million of capitalized cost for plugging liability recorded in the first quarter of 2003 for wells drilled in prior years.

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2004, by the year in which such costs were incurred.

	2004	2003	2002	2001 and Prior	Total
			(In thousands)		
Undeveloped Leasehold Acquired	$15,622	$6,369	$2,415	$3,764	$28,170

Unproved properties not subject to amortization relates to properties which are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the company is unable to estimate when these costs will be included in the amortization calculation.

The results of operations for producing activities are provided below.

	USA	Canada	Total
		(In thousands)	
2002:			
Revenues	$ 64,534	$ 87	$ 64,621
Production costs	(17,300)	(25)	(17,325)
Depreciation, depletion and amortization	(22,685)	(45)	(22,730)
	24,549	17	24,566
Income tax expense	(8,436)	(5)	(8,441)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 16,113	$ 12	$ 16,125
2003:			
Revenues	$114,398	$171	$114,569
Production costs	(21,366)	(21)	(21,387)
Depreciation, depletion and amortization	(27,059)	(20)	(27,079)
	65,973	130	66,103
Income tax expense	(24,508)	(41)	(24,549)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 41,465	$ 89	$ 41,554
2004:			
Revenues	$181,640	$435	$182,075
Production costs	(36,125)	(38)	(36,163)
Depreciation, depletion and amortization	(47,114)	(96)	(47,210)
	98,401	301	98,702
Income tax expense	(36,752)	(95)	(36,847)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 61,649	$206	$ 61,855

The DD&A rate for Unit's United States properties was $1.42, $1.14 and $1.04 per equivalent Mcf in 2004, 2003 and 2002, respectively. The DD&A rate for Canada was $0.69, $0.51 and $1.11 per equivalent Mcf in 2004, 2003 and 2002, respectively.

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)			
2002:						
Proved developed and undeveloped reserves:						
Beginning of year	4,343	227,865	—	389	4,343	228,254
Revision of previous estimates	(166)	(10,543)	—	(31)	(166)	(10,574)
Extensions, discoveries and other additions	230	29,541	—	—	230	29,541
Purchases of minerals in place	192	16,558	—	—	192	16,558
Sales of minerals in place	(30)	—	—	—	(30)	—
Production	(473)	(18,927)	—	(41)	(473)	(18,968)
End of Year	4,096	244,494	—	317	4,096	244,811
Proved developed reserves:						
Beginning of year	2,753	150,419	—	338	2,753	150,757
End of year	2,951	168,049	—	317	2,951	168,366
2003:						
Proved developed and undeveloped reserves:						
Beginning of year	4,096	244,494	—	317	4,096	244,811
Revision of previous estimates	629	(10,510)	—	371	629	(10,139)
Extensions, discoveries and other additions	1,000	39,762	—	—	1,000	39,762
Purchases of minerals in place	8	437	—	—	8	437
Sales of minerals in place	(76)	(31)	—	—	(76)	(31)
Production	(516)	(20,610)	—	(38)	(516)	(20,648)
End of Year	5,141	253,542	—	650	5,141	254,192
Proved developed reserves:						
Beginning of year	2,951	168,049	—	317	2,951	168,366
End of year	3,984	182,203	—	650	3,984	182,853
2004:						
Proved developed and undeveloped reserves:						
Beginning of year	5,141	253,542	—	650	5,141	254,192
Revision of previous estimates	1,230	(10,035)	—	(251)	1,230	(10,286)
Extensions, discoveries and other additions	512	38,402	—	—	512	38,402
Purchases of minerals in place	2,743	40,275	—	—	2,743	40,275
Sales of minerals in place	(17)	(28)	—	—	(17)	(28)
Production	(1,048)	(27,010)	—	(139)	(1,048)	(27,149)
End of Year	8,561	295,146	—	260	8,561	295,406
Proved developed reserves:						
Beginning of year	3,984	182,203	—	650	3,984	182,853
End of year	7,030	223,351	—	260	7,030	223,611

(1) Oil includes natural gas liquids in barrels.

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

Proved oil and gas reserves, as defined in SEC Rule 4-10(a), are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

- that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and
- the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the “proved” classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”;
- crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
- crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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)	
2002:			
Future cash flows	$1,256,434	$1,400	$1,257,834
Future production costs	(320,940)	(309)	(321,249)
Future development costs	(65,266)	—	(65,266)
Future income tax expenses	(250,413)	(233)	(250,646)
Future net cash flows	619,815	858	620,673
10% annual discount for estimated timing of cash flows	(275,015)	(344)	(275,359)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 344,800	$ 514	$ 345,314
2003:			
Future cash flows	$1,548,785	$3,500	$1,552,285
Future production costs	(418,007)	(581)	(418,588)
Future development costs	(72,891)	—	(72,891)
Future income tax expenses	(313,827)	(805)	(314,632)
Future net cash flows	744,060	2,114	746,174
10% annual discount for estimated timing of cash flows	(325,182)	(738)	(325,920)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 418,878	$1,376	$ 420,254
2004:			
Future cash flows	$1,987,064	$1,467	$1,988,531
Future production costs	(515,392)	(325)	(515,717)
Future development costs	(94,590)	—	(94,590)
Future income tax expenses	(469,833)	(250)	(470,083)
Future net cash flows	907,249	892	908,141
10% annual discount for estimated timing of cash flows	(386,233)	(296)	(386,529)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 521,016	$ 596	$ 521,612

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

	USA	Canada	Total
		(In thousands)	
2002:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (47,230)	$ (62)	$ (47,292)
Net changes in prices and production costs	230,934	363	231,297
Revisions in quantity estimates and changes in production timing	(49,000)	(110)	(49,110)
Extensions, discoveries and improved recovery, less related costs	60,957	—	60,957
Changes in estimated future development cost	1,743	—	1,743
Previously estimated cost incurred during the period	9,911	30	9,941
Purchases of minerals in place	23,334	—	23,334
Sales of minerals in place	(150)	—	(150)
Accretion of discount	23,080	39	23,119
Net change in income taxes	(84,843)	(59)	(84,902)
Other—net	(1,213)	7	(1,206)
Net change	167,523	208	167,731
Beginning of year	177,277	306	177,583
End of year	$344,800	$ 514	$345,314
2003:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (93,948)	$ (150)	$ (94,098)
Net changes in prices and production costs	65,611	195	65,806
Revisions in quantity estimates and changes in production timing	(14,637)	1,007	(13,630)
Extensions, discoveries and improved recovery, less related costs	113,421	—	113,421
Changes in estimated future development cost	(5,356)	—	(5,356)
Previously estimated cost incurred during the period	15,664	—	15,664
Purchases of minerals in place	881	—	881
Sales of minerals in place	(837)	—	(837)
Accretion of discount	48,317	66	48,383
Net change in income taxes	(38,950)	(386)	(39,336)
Other—net	(16,088)	130	(15,958)
Net change	74,078	862	74,940
Beginning of year	344,800	514	345,314
End of year	$418,878	$1,376	$420,254

	USA	Canada	Total
		(In thousands)	
2004:			
Sales and transfers of oil and natural gas produced, net of production costs	$(145,265)	$ (647)	$(145,912)
Net changes in prices and production costs	39,017	(3)	39,014
Revisions in quantity estimates and changes in production timing	(6,267)	(721)	(6,988)
Extensions, discoveries and improved recovery, less related costs	116,362	—	116,362
Changes in estimated future development cost	(6,604)	—	(6,604)
Previously estimated cost incurred during the period	15,655	—	15,655
Purchases of minerals in place	132,960	—	132,960
Sales of minerals in place	(226)	—	(226)
Accretion of discount	59,619	191	59,810
Net change in income taxes	(87,961)	354	(87,607)
Other—net	(15,152)	46	(15,106)
Net change	102,138	(780)	101,358
Beginning of year	418,878	1,376	420,254
End of year	$ 521,016	$ 596	$ 521,612

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 difficulty 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 $43.45 and natural gas $5.65 relating to proved reserves to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

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

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

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

None.

Item 9a. ***Controls and Procedures.***

(a) **Evaluation of Disclosure Controls and Procedures**

The company maintains "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act"), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is collected and communicated to management, including the company's Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards. Based on their evaluation as of the end of the period covered by this Annual Report on Form 10-K, the Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the company's disclosure controls and procedures were effective to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to them by others within those entities.

(b) **Management's Report on Internal Control Over Financial Reporting**

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that its internal control over financial reporting was effective as of December 31, 2004.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included in this report.

(c) **Changes in Internal Control Over Financial Reporting**

As of the last quarter, there were no changes in the company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Item 9b. ***Other Information.***

The following describes the ordinary course executive officer compensation actions taken by the Compensation Committee of the Board of Directors of the company (the "Committee").

At its meetings on December 14, 2004, to be effective January 1, 2005, the Committee took the following actions with respect to the discretionary compensation of the company's named executive officers (as defined in Regulation S-K item 402(a)(3)):

Executive Officer	2005 Salary	Bonus (1)	Stock Option Award (2)
John G. Nikkel Chief Executive Officer	(3)	n/a (4)	n/a
Larry D. Pinkston President and Chief Operating Officer	$250,000	$150,000	10,000 shares
Mark E. Schell Senior Vice President, General Counsel and Secretary	$190,000	$125,000	8,500 shares
David T. Merrill Chief Financial Officer and Treasurer	$178,200	$ 60,000	5,000 shares

(1) Bonus awards are paid out in three equal annual installments commencing in 2005. To receive future installments the individual must remain employed with the company.

(2) Option grants vest in 20% increments commencing one year from the date of grant. Options are awarded at the fair market value of the company's common stock on the date of grant.

(3) No salary increase for 2005. Mr. Nikkel, as previously reported, has announced his intention to retire as the CEO of the company effective April 1, 2005.

(4) As previously reported, on February 16, 2005, the Compensation Committee elected to reward Mr. Nikkel for his 21 years of service to the company by awarding him a cash bonus of $750,000, payable in 24 equal monthly installments commencing on the 20th month following his retirement on April 1, 2005.

PART III

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

The information regarding Directors and Executive Officers appearing under the headings "Item 1: Election of Directors", and "Other Matters" of our 2005 Proxy Statement is incorporated by reference in this section. The information under the heading "Executive Officers" in Items 1 and 2 of this Form 10-K is also incorporated by reference in this section.

Item 11. ***Executive Compensation***

The information appearing under the headings "Directors' Compensation and Benefits", "Executive Compensation", "Termination of Employment & Change in Control Arrangements", "Compensation Committee Interlocks and Insider Participation" and "Report of the Compensation Committee" of our 2005 Proxy Statement is incorporated by reference.

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

The information appearing under the heading "Ownership of Our Common Stock by Beneficial Owners and Management" of our 2005 Proxy Statement is incorporated by reference.

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

The information appearing under the heading "Other Matters" of our 2005 Proxy Statement is incorporated by reference.

Item 14. ***Principal Accounting Fees and Services.***

The information appearing under the headings "Report of Audit Committee", "Principal Accounting Fees and Services" and "Ratification of Appointment of Auditors" of our 2005 Proxy Statement is incorporated by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) Financial Statements, Schedules and Exhibits:

1. ***Financial Statements:***

Included in Part II of this report:

Consolidated Balance Sheets as of December 31, 2004 and 2003
Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2002, 2003 and 2004
Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002
Notes to Consolidated Financial Statements
Report of Independent Registered Public Accounting Firm

2. ***Financial Statement Schedules:***

Included in Part IV of this report for the years ended December 31, 2004, 2003 and 2002:

Schedule II—Valuation and Qualifying Accounts and Reserves

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

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

3. ***Exhibits:***

2.6.1	Amended and Restated Stock Purchase Agreement dated as of June 24, 2002 by and among Unit Corporation, George B. Kaiser and Kaiser Francis Oil Company (incorporated herein by reference to Exhibit 99.1 to Form 8-K dated August 27,2002).
2.6.2	Amended and Restated Share Purchase Agreement dated as of June 24, 2002, by and among Unit Corporation, Kaiser Francis Charitable Income Trust B and Kaiser Francis Oil Company (incorporated herein by reference to Exhibit 99.2 to Form 8-K dated August 27, 2002).
3.1	Restated Certificate of Incorporation of Unit Corporation (filed as Exhibit 3.1 to Form S-3 (file No. 333-83551), which is incorporated herein by reference).
3.2	By-Laws of Unit Corporation as amended through February 15, 2005 (filed as Exhibit 3.1 to Unit's Form 8-K, dated February 22, 2005 which is incorporated herein by reference).
4.2.3	Form of Common Stock Certificate (filed as Exhibit 4.1 on Form S-3 as S.E.C. File No. 333-83551, which is incorporated herein by reference).
4.2.6	Rights Agreement between Unit Corporation and Chemical Bank, as Rights Agent (filed as Exhibit 1 to Unit's Form 8-A filed with the S.E.C. on May 23, 1995, File No. 1-92601 and incorporated herein by reference).
4.2.7	First Amendment of Rights Agreement dated May 19, 1995, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed as Exhibit 4 to Unit's Form 8-K dated August 23, 2001, which is incorporated herein by reference).

4.2.8	Second Amendment of the Rights Agreement, dated August 14, 2002, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002, which is incorporated herein by reference).
4.3	Indenture (filed as Exhibit 4.3 to Unit's Form S-3 filed with the S.E.C. File No. 333-104165, which is incorporated herein by reference).
10.1.26	Credit Agreement dated January 30, 2004 (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2003, which is incorporated herein by reference).
10.2.2	Unit 1979 Oil and Gas Program Agreement of Limited Partnership (filed as Exhibit I to Unit Drilling and Exploration Company's Registration Statement on Form S-1 as S.E.C. File No. 2-66347, which is incorporated herein by reference).
10.2.10	Unit 1984 Oil and Gas Program Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1984 Oil and Gas Program's Registration Statement Form S-1 as S.E.C. File No. 2-92582, which is incorporated herein by reference).
10.2.21*	Unit Drilling and Exploration Employee Bonus Plan (filed as Exhibit 10.16 to Unit's Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).
10.2.22*	The Company's Amended and Restated Stock Option Plan (filed as an Exhibit to Unit's Registration Statement on Form S-8 as S.E.C. File No's. 33-19652, 33-44103 and 33-64323 which is incorporated herein by reference).
10.2.23*	Unit Corporation Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-49724, which is incorporated herein by reference).
10.2.24*	Unit Corporation Employees' Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).
10.2.25	Unit Consolidated Employee Oil and Gas Limited Partnership Agreement (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.27*	Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.30*	Separation Benefit Plan of Unit Corporation and Participating Subsidiaries as amended (filed as Exhibit 10.1 to Unit's Form 8-K dated December 20, 2004).
10.2.32*	Unit Corporation Separation Benefit Plan for Senior Management as amended (filed as an Exhibit 10.1 to Unit's Form 8-K dated December 20, 2004).
10.2.33*	Unit Corporation Special Separation Benefit Plan as amended (filed as Exhibit 10.3 to Unit's Form 8-K dated December 20, 2004).
10.2.35	Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 1999).
10.2.36*	Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 333-38166, which is incorporated herein by reference).
10.2.37*	Unit Corporation's Amended and Restated Stock Option Plan (filed as an Exhibit to Unit's Registration Statement on Form S-8 as S.E.C. File No. 333-39584 which is incorporated herein by reference).

10.2.38	Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).
10.2.40	Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as Exhibit 10.1 to Unit's Form 8-K dated February 22, 2005, which is incorporated herein by reference).
10.2.41	Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2001).
10.2.42	Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002).
10.2.43	Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2003).
10.2.44	Unit 2005 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herein).
21	Subsidiaries of the Registrant (filed herein).
23.1	Consent of Registered Public Accounting Firm (filed herein).
23.2	Consent of Independent Petroleum Engineers (filed herein).
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
32.1	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein).
99.2*	Separation Agreement, dated May 11, 2001, between the Registrant and Mr. Kirchner (filed as Exhibit 99.4 to Unit's Form 8-K dated May 18, 2001, which is incorporated herein by reference).
99.2*	Consulting Agreement, dated December 16, 2004, between John G. Nikkel and the Registrant (filed as Exhibit 10.4 to Unit's Form 8-K dated December 20, 2004).

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

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, 2004	$1,223	$400	$ (38)	$1,661
Year ended December 31, 2003	$1,203	$645	$625	$1,223
Year ended December 31, 2002	$ 604	$603	$ 4	$1,203

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 14, 2005

By: /s/ JOHN G. NIKKEL

JOHN G. NIKKEL
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 14th day of March, 2005.

Name	Title
/s/ JOHN G. NIKKEL **John G. Nikkel**	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)
/s/ LARRY D. PINKSTON **Larry D. Pinkston**	Director, President, Chief Operating Officer
/s/ DAVID T. MERRILL **David T. Merrill**	Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ STANLEY W. BELITZ **Stanley W. Belitz**	Controller (Principal Accounting Officer)
/s/ J. MICHAEL ADCOCK **J. Michael Adcock**	Director
/s/ DON COOK **Don Cook**	Director
/s/ KING P. KIRCHNER **King P. Kirchner**	Director
/s/ MARK E. MONROE **Mark E. Monroe**	Director
/s/ WILLIAM B. MORGAN **William B. Morgan**	Director
/s/ JOHN H. WILLIAMS **John H. Williams**	Director