UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2006

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 or other jurisdiction of incorporation or organization)	**(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

[None]

(Former name, former address and former fiscal year, if changed since last report)

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	NYSE
Rights to Purchase Series A Participating Cumulative Preferred Stock	NYSE

Securities registered pursuant to Section 12(g) of the Act: [None]

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
Yes ☐ No ☒

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 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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

As of June 30, 2006, there were outstanding 46,275,670 shares of common stock, par value $0.20, and the aggregate market value of the common stock (based on the closing price of the stock on the New York Stock Exchange on June 30, 2006) held by non-affiliates was approximately $2,590,972,901. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the Registrant is not bound by these determinations for any other purpose.

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

Class	Outstanding at February 16, 2007
Common Stock, $0.20 par value per share	46,290,797 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the Registrant's Definitive Proxy Statement (the "Proxy Statement") with respect to its annual meeting of shareholders scheduled to be held on May 2, 2007.	Part III

Exhibit Index—See Page 96

FORM 10-K
UNIT CORPORATION

TABLE OF CONTENTS

UNIT CORPORATION

Annual Report
For The Year Ended December 31, 2006

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, Midland and Weatherford Texas; Casper, Wyoming; Oklahoma City, Wilburton and Woodward, Oklahoma; and Denver, Colorado.

Information regarding our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports, will be made available in print, free of charge, to any shareholder who request them, or at our internet website at www.unitcorp.com, as soon as reasonably practicable after we electronically file these reports with or furnish them to the SEC. Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 100 F. Street, N.E. Room 1580, 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.

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. Information regarding our corporate governance guidelines and code of ethics, and the charters of our Board's Audit, Compensation and Nomination and Governance Committees, are available free of charge on our website listed above or in print to any shareholder who request them.

Unless otherwise indicated or required by the context, as 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.*

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 ("land contract drilling"),
- explore, develop, acquire and produce oil and natural gas properties for our own account ("oil and natural gas exploration"), and
- buy, sell, gather, process and treat natural gas for our own account and for third parties ("mid-stream").

The following table provides certain information about us as of February 16, 2007:

Number of drilling rigs we own	117
Number of wells in which we own an interest	7,462
Number of natural gas treatment plants we own	3
Number of operating processing plants we own	6
Number of active natural gas gathering systems we own	37
States in which our principal operations are located	Oklahoma, Texas, Louisiana, Wyoming, Utah, New Mexico, Colorado and Montana

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 land contract drilling business is conducted through two companies, Unit Drilling Company and its subsidiary Unit Texas Drilling L.L.C. Through these companies we drill onshore natural gas and oil wells for our own account as well as for a wide range of other oil and gas companies. Our operations are mainly located in the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the North Texas Barnett Shale, the Texas and Louisiana Gulf Coast and East Texas and the Rocky Mountain regions of Wyoming, Colorado, Utah and Montana.

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

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Number of Drilling Rigs Owned at End of Period	117.0	112.0	100.0	88.0	75.0
Average Number of Drilling Rigs Owned During Period	114.0	105.2	93.0	75.9	61.6
Average Number of Drilling Rigs Utilized	109.0	102.1	88.1	62.9	39.1
Utilization Rate (1)	96%	97%	95%	83%	63%
Average Revenue Per Day (2)	$17,574	$12,401	$9,247	$7,972	$8,285
Total Footage Drilled (Feet in 1,000's)	11,461	10,815	9,261	6,580	3,829
Number of Wells Drilled	1,033	980	832	530	318

(1) Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling 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. As a result of the normal wear and tear of operating 24 hours a day, several of the major components of a drilling rig, 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.

The maximum depth capacities of our various drilling rigs range from 5,000 to 40,000 feet. In 2006, 116 of the 117 rigs we owned during the year performed contract drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 16, 2007:

Region	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depths (ft)
Anadarko Basin Oklahoma	34	4	38	18,365
Panhandle of Texas	17	3	20	13,675
Arkoma Basin	10	—	10	14,350
East Texas and Gulf Coast	15	2	17	18,200
North Texas Barnett Shale	7	1	8	11,600
Rocky Mountains	21	3	24	16,900
Totals	104	13	117	16,430

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. Demand for our drilling rigs increased throughout 2004 and 2005 and our utilization rate remained above 95% throughout the first three quarters of 2006. In the fourth quarter of 2006 and into the first quarter of 2007, demand for our drilling rigs has declined to around 85%. As we continue to add drilling rigs to our fleet and the national count of available drilling rigs continues to grow, it has become increasingly difficult to find additional qualified labor to work on our drilling rigs. If demand for our drilling rigs remains above 85% and the industry rig count continues to grow, we expect competition for qualified labor to continue which will result in higher operating costs.

The following table shows the average number of drilling rigs working by quarter for the years indicated:

	2006	2005	2004
First Quarter	108.6	99.3	81.7
Second Quarter	110.3	100.3	83.7
Third Quarter	110.6	102.6	92.0
Fourth Quarter	106.7	106.2	95.0

Drilling Rig Fleet. The following table summarizes the changes to our drilling rig fleet during 2006. A more complete discussion of these changes follows the table:

Number of drilling rigs owned at December 31, 2005	112
Number of drilling rig reductions during 2006	(1)
Number of drilling rigs purchased during 2006	1
Number of drilling rigs constructed or had constructed during 2006	5
Total drilling rigs owned at December 31, 2006	117

Reductions. In January 2006, we experienced a fire on one of our drilling rigs. Drilling rig No. 31, a 600 horsepower drilling rig and one of our smaller drilling rigs, experienced a blowout during initial drilling operations at an approximate depth of 800 feet. No personnel were injured although the drilling rig was a total loss. Insurance proceeds for the loss did not cover the replacement cost for a new rig, but exceeded our net book value and provided a gain of approximately $1.0 million which was recorded in other revenues.

Acquisitions and Construction. In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired drilling rig was modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May we began moving a 1,500 horsepower drilling rig to our Rocky Mountain Division which we completed construction of during the first quarter of 2006 for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two 1,500 horsepower drilling rigs for $15.2 million with $4.6 million paid prior to second quarter of 2006 and the remaining $10.6 million paid at delivery. An additional $3.0 million of modifications were made to the rigs prior to the two rigs being placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower rig for approximately $9.5 million which was moved into our Rocky Mountain Division. In the last half of 2006 we constructed a 750 horsepower rig for an estimated $4.5 million which was available for service in the later part of December of 2006. The addition of this rig minus the one destroyed by fire brought our rig fleet to 117 at December 31, 2006.

During 2006 we paid $4.5 million for the purchase of major components to construct two 1,500 horsepower drilling rigs. The rigs should be placed in service in the first and second quarters of 2007.

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 drilling 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 2006 and 2005, we did not drill any turnkey wells. Due to high demand for our drilling rigs, we are able to perform most of our work under daywork contracts to the exclusion of footage or turnkey contracts. Because market demand for our drilling rigs as well as the desires of our customers determine the types of contracts we use, we cannot predict when and if a part of our drilling will be conducted under turnkey contracts.

Most of our current contracts are not long-term and generally provide for the drilling of one well. We do have some contracts that have terms ranging from one to two years. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Customers. During 2006, 10 customers accounted for approximately 45% of our contract drilling revenues. Chesapeake Operating, Inc. was our largest customer providing 10% of our total contract drilling revenues. During 2006 and 2005, we drilled 72 and 53 wells, respectively for our exploration and production subsidiary reducing carrying value or our oil and natural gas properties. As required by the SEC, the profit received by our contract drilling subsidiary when we drill wells for our exploration and production subsidiary reduced the carrying value of our oil and natural gas properties by $22.2 million and $8.6 million during 2006 and 2005, respectively, 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 and 10 of the Notes to Consolidated Financial Statements in Item 8 of this report.

OUR OIL AND NATURAL GAS EXPLORATION BUSINESS

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

The following table presents certain information regarding our oil and gas operations as of December 31, 2006:

Property/Area	Number of Gross Wells	Number of Net Wells	2006 Average Net Daily Production Mcf	2006 Average Net Daily Production Bbls
Western Division (consists principally of the Rocky Mountain Region, New Mexico, Western and Southern Texas and the Gulf Coast Region)	3,138	483.87	34,929	2,468
East Division (consists principally of the Appalachian Region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	922	208.91	48,485	52
Central Division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	3,378	806.99	37,547	1,461
Canada	5	0.96	51	—
Total	7,443	1,500.73	121,012	3,981

When we are the operator of a property, we generally attempt to use a drilling rig owned by one of our subsidiaries.

Acquisitions. On May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition are included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. This acquisition included all of Brighton's oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and was included in our statement of income starting in October 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

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,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploratory:						
Oil	—	—	1	0.31	1	0.05
Natural gas	5	2.39	6	1.91	5	1.42
Dry	5	2.24	2	2.00	1	0.31
	10	4.63	9	4.22	7	1.78
Development:						
Oil	12	2.62	15	4.94	17	5.71
Natural gas	199	67.93	157	58.08	121	48.60
Dry	23	10.12	11	5.39	23	13.40
	234	80.67	183	68.41	161	67.71
Total	244	85.30	192	72.63	168	69.49

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Oil and Natural Gas Wells Producing or Capable of Producing:						
Oil—USA	2,783	492.87	2,745	428.90	2,715	418.51
Oil—Canada	1	0.03	1	0.03	1	0.03
Natural Gas—USA	4,655	1,006.90	3,717	829.60	3,103	670.62
Natural Gas—Canada	4	0.93	2	0.40	66	2.00
Total	7,443	1,500.73	6,465	1,258.93	5,885	1,091.16

As of February 16, 2007, we have participated in the drilling of 19 gross (8.47 net) wells during 2007.

Cost incurred for development drilling includes $34.3 million, $31.9 million and $16.0 million in 2006, 2005 and 2004, 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
2006 (1):				
USA	1,018,616	292,613	364,914	179,329
Canada	1,282	257	6,400	3,413
Total	1,019,898	292,870	371,314	182,742
2005:				
USA	901,157	259,420	338,623	171,222
Canada	760	152	7,040	3,541
Total	901,917	259,572	345,663	174,763
2004:				
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

(1) Approximately 75% of the net undeveloped acres are covered by leases that will expire in each of the years 2007–2009 unless drilling or production 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 2007, 2008 and 2009, as disclosed in our December 31, 2006 oil and natural gas reserve report, are $136.7 million, $60.6 million and $9.2 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,		
	2006	**2005**	**2004**
Average Sales Price per Barrel of Oil Produced:			
USA price before hedging	$ 55.11	$ 50.14	$ 36.63
Effect of hedging	—	—	(3.43)
USA price including hedging	$ 55.11	$ 50.14	$ 33.20
Canada	$ —	$ —	$ —
Average Sales Price per Mcf of Natural Gas Produced:			
USA price before hedging	$ 6.16	$ 7.76	$ 5.43
Effect of hedging	—	(0.12)	—
USA price including hedging	$ 6.16	$ 7.64	$ 5.43
Canada price before hedging (U.S. Dollars)	$ 10.58	$ 5.43	$ 4.91
Effect of hedging (U.S. Dollars)	—	—	—
Canada price including hedging (U.S. Dollars)	$ 10.58	$ 5.43	$ 4.91
Oil Production (MBbls):			
USA	1,453	1,084	1,048
Canada	—	—	—
Total	1,453	1,084	1,048
Natural Gas Production (MMcf):			
USA	44,151	33,997	27,010
Canada	18	61	139
Total	44,169	34,058	27,149
Average Production Cost per Equivalent Mcf:			
USA	$ 1.37	$ 1.36	$ 1.08
Canada	$ 1.17	$ 1.14	$ 0.42

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

	Year Ended December 31,		
	2006	**2005**	**2004**
Oil (MBbls):			
USA	11,583	9,871	8,561
Canada	—	—	—
Total	11,583	9,871	8,561
Natural Gas (MMcf):			
USA	406,263	352,685	295,146
Canada	137	156	260
Total	406,400	352,841	295,406

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. In 2006, purchases by Eagle Energy Partners I, L.P., ONEOK and ConocoPhillips Company accounted for approximately 17%, 16% and 10% of Unit's oil and natural gas revenues, respectively. During 2006, Superior purchased $8.0 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $5.3 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas exploration operations has been eliminated in our consolidated condensed financial statements. In 2005, we eliminated intercompany revenues of $6.7 million of natural gas and $95,000 of natural gas liquids and in 2004, $1.8 million of natural gas and $53,000 of natural gas liquids.

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

OUR MID-STREAM BUSINESS

General. In July 2004, we acquired the 60% of Superior Pipeline Company, L.L.C. (Superior) that we did not already own. Before July 2004, we owned 18 gathering systems which have now been consolidated with Superior's systems. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, six operating processing plants, 37 active gathering systems and 600 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas. It has been in business since 1996. The acquisition and consolidation increased 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 mid-stream operations for the years indicated:

	Year Ended December 31,		
	2006	2005	2004
Gas Gathered—MMBtu/day	247,537	142,444	33,147
Gas Processed—MMBtu/day	31,833	30,613	13,412

Acquisitions. In September 2006, our mid-stream operations closed the acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consist of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in our statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

Additional Information. Further information relating to our mid-stream operations is contained 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 prices we received by quarter, taking into account the effect of our hedging activity, for each of the periods indicated:

	Average Monthly Natural Gas Price per Mcf		Average Monthly Oil Price per Bbl	
QUARTER	**High**	**Low**	**High**	**Low**
2006:				
First	$ 7.99	$6.13	$58.41	$51.74
Second	$ 6.06	$5.46	$58.99	$54.45
Third	$ 6.74	$5.55	$62.43	$55.35
Fourth	$ 6.72	$4.50	$50.56	$48.54
2005:				
First	$ 6.00	$5.39	$47.95	$42.67
Second	$ 6.95	$5.65	$49.02	$43.30
Third	$ 9.97	$6.95	$56.92	$51.10
Fourth	$10.35	$9.33	$56.11	$54.03
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

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, Nigeria 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 natural gas or oil 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. You are encouraged to read the Risk Factors discussed in Item 1A of this report for additional risks that can impact our operations.

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. Both demand for our drilling rigs and dayrates steadily increased over 2005 and the first three quarters of 2006, before declining late in the fourth quarter of 2006. In January 2005, the average dayrate for our drilling rigs was $9,994 per day with a 97% utilization rate. In December 2006, our average dayrate was $19,930 with an 88% utilization rate. The decrease in utilization during the fourth quarter was, in part, due to the decline in the price of natural gas as well as concerns regarding future demand for natural gas on the part of our customers. Since short-term and long-term trends in oil and natural gas prices affect the demand for our drilling rigs, the future demand for and the dayrates we will receive for our drilling services is uncertain.

Our mid-stream 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 oil, natural gas and natural gas liquids 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 us to extract certain natural gas liquids. The volumes of natural gas processed are 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 the land contract drilling business traditionally involves factors such as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our land contract drilling competitors are substantially larger than we are and have greater 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 mid-stream 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 and availability of services, reputation and the flexibility and reliability of service.

As discussed elsewhere in this report, throughout 2005 and 2006 all of our operations experienced strong competition for qualified labor. If demand for our services and products continue at the levels experienced during 2005 and 2006, we anticipate this competition will also continue.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 12 oil and gas limited partnerships. Three of these partnerships were formed for investment by third parties and nine (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 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 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 of our interest in the wells.

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 February 16, 2007, we had approximately 2,567 employees in our land contract drilling operations, 138 employees in our oil and natural gas exploration operations, 49 employees in our mid-stream operations and 92 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.

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.

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. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained in this report. 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;
- the amount of wells we plan to drill or rework;
- prices for oil and natural gas;
- demand for oil and natural gas;

- our exploration prospects;
- the estimates of our proved oil and natural gas reserves;
- oil and natural gas reserve potential;
- development and infill drilling potential;
- our drilling prospects;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas reserves;
- growth potential for our mid-stream operations;
- gathering systems and processing plants we plan to construct or acquire;
- 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. Except as required by law, 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 help provide you with 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 some (but not all) of the factors that in the future could cause our 2007 consolidated results and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

Oil and Natural Gas 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 2006 production, a $0.10 per Mcf change in what we receive for our natural gas production would result in a corresponding $344,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price would have a $113,000 per month ($1.4 million annualized) change in our pre-tax operating cash flow. During 2006, 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 arrangements such as swaps and collars. Our hedging 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 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 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 based on 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 operate 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 information included in this report represents only an estimate of these reserves. Oil and natural gas reservoir engineering is a subjective and an 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:

- reservoir size;
- 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 all of our operations. Historically, we have funded our working capital needs through a combination of internally generated cash flow and borrowings under our bank credit facility. We have also, from time to time obtained funds through equity financing. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2006, our outstanding long-term debt was $174.3 million.

Our level of debt, the cash flow needed to satisfy our debt and the covenants contained in our bank credit facility 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 of our cash flow. 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 buying, selling, gathering, processing and treating 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 actually incur them. However, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to make a large acquisition or the need to replace a costly drilling 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.

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 30, 2008. The fixed rate is 3.99%. 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.

EXECUTIVE OFFICERS

The table below and accompanying text sets forth certain information as of February 16, 2007 concerning each of the executive officers of the company as well as certain officers of our subsidiaries. There were no arrangements or understandings between any of the officers and any other person(s) under which the officers were elected.

Name	Age	Position Held
Larry D. Pinkston	52	Chief Executive Officer since April 1, 2005, 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	49	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	46	Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	51	Senior Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	59	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	52	Manager, Superior Pipeline Company, L.L.C. since June 1996

Mr. Pinkston joined the company in December, 1981. He had served as Corporate Budget Director and Assistant Controller before 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. 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. In April 2005, he also began serving as Chief Executive Officer. Mr. Pinkston holds the offices of President, Chief Executive Officer and Chief Operating Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma.

Mr. Schell joined the company 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 the company, 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.

Mr. Merrill joined the company 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.

Mr. Guidry joined Unit Petroleum Company in August 1988 as a Staff Geologist. In 1991, he was promoted to Geologic Manager overseeing the Geologic Operations of the company. In January 2003, he was promoted to Vice President of the West Division. In March 2005, Mr. Guidry was promoted to Senior Vice President of Exploration for Unit Petroleum Company. From 1979 to 1988, he was employed as a Division Geologist for Reading and Bates Petroleum Co. From 1978 to 1979, he worked with ANR Resources in Houston. He began his career as an open hole well logging engineer with Dresser Atlas Oilfield Services. Mr. Guidry graduated from Louisiana State University with a Bachelor of Science degree in Geology.

Mr. Cromling joined Unit Drilling Company in 1997 as a Vice-President and Division Manager. In April 2005, he was promoted to the position of Executive Vice-President of Drilling for Unit Drilling Company. In 1980, he formed Cromling Drilling Company which managed and operated drilling rigs until 1987. From 1987 to 1997, Cromling Drilling Company provided engineering consulting services and generated and drilled oil and natural gas prospects. Prior to this, he was employed by Big Chief Drilling for 11 years and served as Vice-President. Mr. Cromling graduated from the University of Oklahoma with a degree in Petroleum Engineering.

Mr. Parks founded Superior Pipeline Company, L.L.C. in 1996. When Superior was acquired by the company in July 2004, he continued with Superior as one of its managers and as its President. From April 1992 through April 1996 Mr. Parks served as Vice-President—Gathering and Processing for Cimarron Gas Companies. From December 1986 through March 1992, he served as Vice-President—Business Development for American Central Gas Companies. Mr. Parks began his career as an engineer with Cities Service Company in 1978. He received a Bachelor of Science degree in Chemical Engineering from Rice University and his M.B.A. from the University of Texas at Austin.

Item 1A. *Risk Factors.*

There are a number of other factors associated with our business that could adversely affect our business. The following discussion describes the material risks currently known to us. However, additional risks that we do not know about or that we currently view as immaterial may also impair our business or adversely affect the value of our securities. You should carefully consider the risks described below together with the other information contained in, or incorporated by reference into, this report.

Oil and natural gas prices are volatile, and low prices have negatively affected our financial results and could do so in the future.

Our revenues, operating results, cash flow and future rate of growth depend substantially on prevailing prices for oil and natural gas. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future. Any decline in prices in the future would have a negative impact on our future financial results. Because our oil and natural gas reserves are predominantly natural gas, significant changes in natural gas prices would have a particularly large impact on our financial results.

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

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

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

Our contract drilling operations depend on levels of activity in the oil and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil and natural gas exploration and production in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect the level of that activity. Because oil and natural gas prices are volatile, the level of exploration and production activity can also be volatile. Any decrease from current oil and natural gas prices would depress the level of exploration and production activity. This, in turn, would likely result in a decline in the demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows and profitability. As a result, the future demand for our drilling services is uncertain.

The industries in which we operate are highly competitive, and many of our competitors have greater resources than we do.

The drilling industry in which we operate is generally very competitive. Most drilling contracts are awarded on the basis of competitive bids, which may result in intense price competition. Many of our competitors in the contract drilling industry have greater financial and human resources than we do. These resources may enable them to better withstand periods of low drilling rig utilization, to compete more effectively on the basis of price and technology, to build new drilling rigs or acquire existing drilling rigs and to provide drilling rigs more quickly than we do in periods of high drilling rig utilization.

The oil and natural gas industry is also highly competitive. We compete in the areas of property acquisitions and oil and natural gas exploration, development, production and marketing with major oil companies, other independent oil and natural gas concerns and individual producers and operators. In addition, we must compete with major and independent oil and natural gas concerns in recruiting and retaining qualified employees. Many of our competitors in the oil and natural gas industry have substantially greater resources than we do.

Shortages of experienced personnel for our contract drilling operations could limit our ability to meet the demand for our services.

During periods of increasing demand for contract drilling services, the industry may experience shortages of qualified drilling rig personnel. During these periods, our ability to attract and retain sufficient qualified personnel to market and operate our drilling rigs is adversely affected which negatively impacts both our operations and profitability. Operationally, it is more difficult to hire qualified personnel, which adversely affects our ability to mobilize inactive drilling rigs in response to the increased demand for our contract drilling services. Additionally, wage rates for drilling personnel are likely to increase, resulting in greater operating costs.

Shortages of drill pipe, replacement parts and other related drilling rig equipment adversely affect our operating results.

During periods of increased demand for drilling services, the industry has experienced shortages of drill pipe, replacement parts and other related drilling rig equipment. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. These price increases and delays in delivery may require us to increase capital and repairs expenditures in our contract drilling segment. Severe shortages could impair our ability to operate our drilling rigs.

Continued growth through acquisitions is not assured.

Over the past several years, we have increased each of our various operation segments, in part, through mergers and acquisitions. The land drilling industry, the exploration and development industry, as well as the gas gathering and processing industry, have experienced significant consolidation over the past several years, and there can be no assurance that acquisition opportunities will continue to be available. Additionally, we are likely to continue to face intense competition from other companies for available acquisition opportunities.

There can be no assurance that we will:

- be able to identify suitable acquisition opportunities;
- have sufficient capital resources to complete additional acquisitions;
- successfully integrate acquired operations and assets;
- effectively manage the growth and increased size;
- maintain the crews and market share to operate any future drilling rigs we may acquire; or
- successfully improve our financial condition, results of operations, business or prospects in any material manner as a result of any completed acquisition.

We may incur substantial indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with any acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity would be dilutive to existing shareholders. Also, continued growth could strain our management, operations, employees and other resources.

Successful acquisitions, particularly those of oil and natural gas companies or of oil and natural gas properties require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Our operations have significant capital requirements, and our indebtedness could have important consequences to you.

We have experienced and expect to continue to experience substantial working capital needs because of the growth in all of our operations. On February 16, 2007, our outstanding long-term debt was $160.5 million. Our level of indebtedness, the cash flow needed to satisfy our indebtedness and the covenants governing our indebtedness could:

- limit funds available for financing capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for, or reacting to changes in, our business;
- place us at a competitive disadvantage to some of our competitors that are less leveraged than 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 service and other contractual and contingent obligations will depend on our future performance. In addition, lower oil and natural gas prices could result in future reductions in the amount available for borrowing under our credit facility, reducing our liquidity and even triggering mandatory loan repayments.

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 reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account through exploration and development. We have conducted these activities on our existing oil and natural gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from these activities at acceptable costs. Lower prices of oil and natural gas may further limit the kinds of reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

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

The competition for producing oil and natural gas properties is intense. This competition could mean that to acquire properties we will have to pay higher prices and accept greater ownership risks than we have in the past.

Our exploration and production operations involve a high degree of business and financial risk which could adversely affect us.

Exploration and development involve numerous risks that may result in dry holes, the failure to produce oil and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing and operating wells is substantial and uncertain. Numerous factors beyond our control may cause the curtailment, delay or cancellation of drilling operations, including:

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

Exploratory drilling is a speculative activity. Although we may disclose our overall drilling success rate, those rates may decline. Although we may discuss drilling prospects that we have identified or budgeted for, we may ultimately not lease or drill these prospects within the expected time frame, or at all. Lack of drilling success will have an adverse effect on our future results of operations and financial condition.

Our mid-stream operations involve numerous risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial and our ability to recoup these cost is 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 competing 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.

Our hedging arrangements might limit the benefit of increases in oil and natural gas prices.

In order to reduce our exposure to short-term fluctuations in the price of oil and natural gas, we sometimes enter into hedging arrangements. Our hedging 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 arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices.

Estimates of our reserves are uncertain and may prove to be inaccurate, and oil and natural gas price declines may lead to an impairment of our oil and natural gas assets.

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

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

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

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

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

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

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

Our operations present inherent risks of loss that, if not insured or indemnified against, could adversely affect our results of operations.

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

In addition, we are not the operator of many of our wells. As a result, our operating risks for those wells and our ability to influence the operations for those wells are less subject to our control. Operators of those wells may act in ways that are not in our best interests.

Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

We are also subject to complex environmental laws and regulations adopted by the various jurisdictions where we own or operate. We could incur liability to governments or third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any number of ways including the following:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators, which liability could be material.

Any future implementation of price controls on oil and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either natural gas, oil or both. There is no way at this time to know what result these efforts will have nor, if implemented, their effect on our operations. However, it is possible that these efforts, if successful, would serve to limit the amount that we might be able to get for our future oil and natural gas production. Any future limits on the price of oil and natural gas could also result in adversely affecting the demand for our drilling services.

Our shareholders' rights plan and provisions of Delaware law and our by-laws and charter could discourage change in control transactions and prevent shareholders from receiving a premium on their investment.

Our by-laws and charter provide for a classified board of directors with staggered terms and authorizes the board of directors to set the terms of preferred stock. In addition, our charter and Delaware law contain provisions that impose restrictions on business combinations with interested parties. We have also adopted a shareholders' rights plan. Because of our shareholders' rights plan and these provisions of our by-laws, charter and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our shareholders to benefit from transactions that are opposed by an incumbent board of directors.

New technologies may cause our current exploration and drilling methods to become obsolete, resulting in an adverse effect on our production.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected.

The results of our operations depend on our ability to transport oil and gas production to key markets.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

During 2006, we derived a significant portion of our contract drilling revenues from a small number of customers. The loss of any of these customers could have a material adverse effect on our financial condition and results of operations.

During 2006, our 10 largest customers accounted for approximately 45% of our contract drilling revenues. Chesapeake Operating, Inc. was our largest customer providing 10% of our total contract drilling revenues. These customers may not continue to employ our services and the loss of any or a number of these large customers could have a material adverse effect on our financial condition and results of operations. At December 31, 2006 and February 16, 2007, Chesapeake Operating, Inc. had 14 of our drilling rigs under contract, however we have been notified it expects to release seven of our rigs over the next 60 days.

If oil and natural gas prices decrease or are unusually volatile, we may be required to take write-downs of our oil and natural gas properties, the carrying value of our drilling rigs or natural gas gathering and processing systems.

According to the full cost accounting rules of the SEC, 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 our earnings. Once incurred, a write-down of oil and natural gas properties is not reversible.

Our drilling equipment, transportation equipment, gas gathering and processing systems and other property and equipment are carried at cost. We are required to periodically test to see if these values have been impaired whenever events or changes in circumstances suggest the carrying amount may not be recoverable. If any of these assets are 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. Once these values have been reduced, they are not reversible.

Item 1B. ***Unresolved Staff Comments*.**

None.

Item 2. ***Properties*.**

The information called for by this item was consolidated with and disclosed in connection with Item 1. above.

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 2006.

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:

Quarter	2006 High	2006 Low	2005 High	2005 Low
First	$61.88	$48.76	$47.75	$33.79
Second	$64.83	$50.74	$47.75	$35.20
Third	$60.13	$43.56	$56.44	$42.28
Fourth	$52.93	$41.38	$60.00	$45.41

On February 16, 2007, the closing sale price of our common stock, as reported by the New York Stock Exchange, was $48.45 per share. On that date, there were approximately 1,404 holders of record.

We have never declared any cash dividends on our common stock and currently have no plans to declare any dividends on our common stock in the foreseeable future. Any future determination by our board of directors to pay dividends on our common stock will be made only after considering our financial condition, results of operations, capital requirements and other relevant factors. Additionally, our bank credit facility prohibits the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit facility's impact on our ability to pay dividends see "Our Credit Facility" under Item 7 of this report.

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2006, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	607,348(2)	$27.72	2,491,454(3)
Equity compensation plans not approved by security holders	—	—	—
Total	607,348	$27.72	2,491,454

(1) Shares awarded under all above plans may be newly issued, from the company's treasury or acquired in the open market.

(2) This number includes the following:

381,350 stock options outstanding under the company's Amended and Restated Stock Option Plan.
37,452 shares of restricted stock outstanding under the company's Stock Bonus Plan.
68,046 shares of restricted stock and SARs outstanding under the Unit Corporation Stock and Incentive Compensation Plan.
120,500 stock options outstanding under the Non-Employee Directors' Stock Option Plan.

(3) This number reflects 59,500 shares available for issuance under the Non-Employee Directors' Stock Option Plan and 2,431,954 shares available for issuance under the Unit Corporation Stock and Incentive Compensation Plan. No more than 2,000,000 of the shares available under the Unit Corporation Stock and Incentive Compensation Plan may be issued as "incentive stock options". In addition, shares related to grants that are forfeited, terminated, cancelled, expire unexercised, or settled in such manner that all or some of the shares are not issued to a participant shall immediately become available for issuance.

Item 6. ***Selected Financial Data.***

	As of and for the Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands except per share amounts)				
Revenues	$1,162,385	$ 885,608	$ 519,203	$301,377	$187,392
Income Before Cumulative Effect of Change In Accounting Principle	$ 312,177	$ 212,442	$ 90,275	$ 48,864	$ 18,244
Net Income	$ 312,177	$ 212,442	$ 90,275	$ 50,189	$ 18,244
Income Before Cumulative Effect of Change In Accounting Principle per Common Share:					
Basic	$ 6.75	$ 4.62	$ 1.97	$ 1.12	$ 0.47
Diluted	$ 6.72	$ 4.60	$ 1.97	$ 1.12	$ 0.47
Net Income per Common Share:					
Basic	$ 6.75	$ 4.62	$ 1.97	$ 1.15	$ 0.47
Diluted	$ 6.72	$ 4.60	$ 1.97	$ 1.15	$ 0.47
Total Assets	$1,874,096	$1,456,195	$1,023,136	$712,925	$578,163
Long-Term Debt	$ 174,300	$ 145,000	$ 95,500	$ 400	$ 30,500
Other Long-Term Liabilities	$ 55,741	$ 41,981	$ 37,725	$ 17,893	$ 5,439
Cash Dividends per Common Share	$ —	$ —	$ —	$ —	$ —

See Item 7. Management's Discussion of Financial Condition and Results of Operation for a review of 2006, 2005 and 2004 activity.

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

Management's Discussion and Analysis (MD&A) provides an understanding of operating results and financial condition by focusing on changes in key measures from year to year. MD&A is organized in the following sections:

- Financial Condition and Liquidity
- Effects of Inflation
- New Accounting Pronouncements
- Results of Operations

MD&A should be read in conjunction with the Consolidated Financial Statements and related notes included in this report.

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 facility. 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 and oil 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.

Our three principal business segments are:

- land contract drilling carried out by our subsidiary Unit Drilling Company and its subsidiary Unit Texas Drilling, L.L.C.

- oil and natural gas exploration, carried out by our subsidiary Unit Petroleum Company and its subsidiaries; and
- mid-stream operations (consisting of natural gas buying, selling, 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 and for the years ended December 31:

	2006	2005	Percent Change
	(In thousands except percentages)		
Working Capital	$ 71,998	$ 51,173	41%
Long-Term Debt	$ 174,300	$ 145,000	20%
Shareholders' Equity	$1,158,036	$ 836,962	38%
Ratio of Long-Term Debt to Total Capitalization	13.1%	14.8%	(11)%
Net Income	$ 312,177	$ 212,442	47%
Net Cash Provided by Operating Activities	$ 506,702	$ 317,771	59%
Net Cash Used in Investing Activities	$ (540,723)	$(384,996)	40%
Net Cash Provided by Financing Activities	$ 33,663	$ 67,507	(50)%

The following table summarizes certain operating information for the years ended December 31:

	2006	2005	Percent Change
Oil Production (MBbls)	1,453	1,084	34%
Natural Gas Production (MMcf)	44,169	34,058	30%
Average Oil Price Received	$ 55.11	$ 50.14	10%
Average Oil Price Received Excluding Hedge	$ 55.11	$ 50.14	10%
Average Natural Gas Price Received	$ 6.17	$ 7.64	(19)%
Average Natural Gas Price Received Excluding Hedge	$ 6.17	$ 7.76	(20)%
Average Number of Our Drilling Rigs in Use During the Period	109.0	102.1	7%
Total Number of Drilling Rigs Owned at the End of the Period	117	112	4%
Average Dayrate	$ 18,767	$ 12,431	51%
Gas Gathered—MMBtu/day	247,537	142,444	74%
Gas Processed—MMBtu/day	31,833	30,613	4%
Number of Active Natural Gas Gathering Systems	37	36	3%

At December 31, 2006, we had unrestricted cash totaling $0.6 million and we had borrowed $174.3 million of the $275.0 million we had elected to have available under our bank credit facility.

Our Credit Facility. On December 31, 2006, we had a $275.0 revolving credit facility. Borrowings under the credit facility are limited to a commitment amount. On October 10, 2006 we signed a third amendment to our credit facility which raised the commitment amount from $235.0 million to $275.0 million. Borrowings under the credit facility are limited to the commitment amount, but we may elect to have a smaller amount available. At January 1, 2006, we had elected to have the full $235.0 million of the commitment amount available. On June 1, 2006, we elected to reduce the available amount to $175.0 before subsequently raising it to $200.0 million on September 15, 2006 and to the full $275.0 million commitment amount on November 11, 2006. These elections were primarily made based on our requirements to finance both natural gas gathering and producing oil and natural gas property acquisitions. On January 25, 2007 we signed a fourth amendment to our credit facility which extended the maturity date of the credit facility to May 31, 2008. 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 life of the agreement. During 2005 and 2006, we incurred additional origination, agency and syndication fees of $187,500 and $60,000, respectively while amending the credit facility and these fees are being amortized over the remaining life of the agreement. The average interest rate for 2006 was 6.3%. At December 31, 2006 and February 16, 2007, our borrowings were $174.3 million and $160.5 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 a borrowing base of $375.0 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. The determination of our borrowing base also includes an amount representing a small part of the value of our drilling rig fleet (limited to $20.0 million) as well as such loan value as the lenders reasonably attribute to Superior Pipeline Company's cash flow as defined in the credit facility. The credit facility 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, 2006, $170.6 million of our $174.3 million debt was subject to the LIBOR Rate.

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

On December 31, 2006, we were in compliance with the covenants contained in the credit facility.

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. The fixed rate is based on three-month LIBOR and is at 3.99%. The swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was increased by $0.2 million in 2005 and decreased by $0.5 million in 2006. The fair value of the swap was recognized on the December 31, 2006 balance sheet as current and non-current derivative assets totaling $0.7 million and a gain of $0.4 million, net of tax, in accumulated other comprehensive income.

Contractual Commitments. At December 31, 2006, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank Debt (1)	$185,079	$ 9,960	$175,119	$ —	$ —
Retirement Agreements (2)	1,386	725	661	—	—
Operating Leases (3)	3,516	1,181	2,213	122	—
Drill Pipe, Drilling Components and Equipment Purchases, Tubing and Casing (4)	52,949	52,949	—	—	—
SerDrilco Inc. Earn-Out Agreement (5)	17,866	17,866	—	—	—
Total Contractual Obligations	$260,796	$82,681	$177,993	$ 122	$ —

(1) See previous discussion in MD&A regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated using our year end interest rate of 5.7% which includes the effect of the interest rate swap.

(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, is paid in monthly payments of $25,000 which started in July 2003 and continues 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 is paid in quarterly payments of $12,500 through December 31, 2007. In the first quarter of 2005, we recorded $0.7 million in additional employee benefit expense for the present value of a separation agreement made in connection with the retirement of John Nikkel from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $31,250 which started in November 2006 and continuing through October 2008. These liabilities, as presented above, are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston and Midland, Texas; and Denver, Colorado 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 drilling rig equipment and production inventory.

(4) Due to the potential for limited availability of new drill pipe within the industry, we have committed to purchase approximately $42.9 million of drill pipe and drill collars. We have committed to purchase $0.6 million of additional drilling rig components for the construction of new drilling rigs. To provide for the completion of wells, our oil and natural gas segment has committed to purchase $9.4 million of casing and tubing in the first six months of 2007.

(5) On December 8, 2003, the company acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest, L.L.C., for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to receive 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, 2006, the third and final year of the earn-out period, the drilling rigs included in the earn-out provision had cash flow providing an earn-out of approximately $17.9 million.

At December 31, 2006, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	Estimated Amount of Commitment Expiration Per Period				
			(In thousands)		
Deferred Compensation Plan (1)	$ 2,544	Unknown	Unknown	Unknown	Unknown
Separation Benefit Plans (2)	$ 3,516	$ 193	Unknown	Unknown	Unknown
Plugging Liability (3)	$33,692	$ 760	$ 2,303	$ 2,993	$ 27,636
Gas Balancing Liability (4)	$ 1,080	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations (5)	$ —	Unknown	Unknown	Unknown	Unknown
Workers' Compensation Liability (6)	$22,157	$ 6,956	$ 3,635	$ 1,329	$ 10,237

(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 us 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 a participant will vest in his or her earned benefit on the earliest of the participant reaching the age of 65 or serving 20 years with us. At December 31, 2006, there were 33 employees participating in the plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143), we have recorded the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil and natural gas reserves 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 2007, 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. Any repurchases in any one year are limited to 20% of the outstanding units. We made repurchases of $7,000, $4,000 and $14,000 in 2006, 2005 and 2004, respectively.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims, as well as, claims under our self funded occupational benefit plan. These claims are incurred primarily in our contract drilling segment.

Hedging and Swaps. Periodically we hedge the prices to be received 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.

In January and February of 2007, we entered into the following two natural gas collar contracts.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	March through December of 2007
Prices	Floor of $6.00 and a ceiling of $10.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	March through December of 2007
Prices	Floor of $6.25 and a ceiling of $9.25
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

In December 2006, we enter into the following natural gas hedging transaction.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	January through December of 2007
Prices	Floor of $6.00 and a ceiling of $9.60
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

All of the hedges for 2007 are cash flow hedges and there is no material amount of ineffectiveness. The fair value of the hedge made in December 2006 was recognized on the December 31, 2006 balance sheet as current derivative assets totaling $1.4 million and a gain of $0.9 million, net of tax, in accumulated other comprehensive income.

In January 2005, we entered into the following two natural gas collar contracts.

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.30
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

In March 2005, we also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covered the period of April through December of 2005, and had a floor of $45.00 and a ceiling of $69.25 and is based on the underlying commodity price at West Texas Intermediate—NYMEX.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The natural gas collar contracts decreased our 2005 natural gas revenues by $4.1 million. We did not have any oil or natural gas hedging transactions outstanding at December 31, 2005.

During the first and second quarters of 2004, we entered into the following two natural gas collar contracts:

First Contract:

Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2004
Prices	Floor of $4.50 and a ceiling of $6.76
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

Second Contract:

Production volume covered	10,000 MMBtus/day
Period covered	May through October of 2004
Prices	Floor of $5.00 and a ceiling of $7.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

We also entered into an oil hedge covering 1,000 barrels of oil production per day. This transaction covered the period of February through December of 2004 and had an average price of $31.40 and is based on the underlying commodity price at West Texas Intermediate—NYMEX.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The natural gas collar contracts increased our 2004 natural gas revenues by $48,000. 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 February 2005, we entered into an interest rate swap to help manage our exposure to possible future interest rate increases. This contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. This swap is a cash flow hedge. As a result of this interest rate swap, our interest expense was increased by $0.2 million in 2005 and decreased by $0.5 million in 2006. The fair value of the swap was recognized on the December 31, 2006 balance sheet as current and non-current derivative assets totaling $0.7 million and a gain of $0.4 million, net of tax, in accumulated other comprehensive income.

Self-Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.5 million for Oklahoma workers' compensation, as well as claims under our occupation benefits plan to $1.0 million for general liability and 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 types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. If our insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. We have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas. Natural gas comprises 85% 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 2006, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $344,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. Our 2006 average natural gas price was $6.17 compared to an average natural gas price of $7.64 for 2005. A $1.00 per barrel change in our oil price would have a $113,000 per month ($1.4 million annualized) change in our pre-tax operating cash flow based on our production in 2006. Our 2006 average oil price was $55.11 compared with an average oil price of $50.14 received in 2005.

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 facility 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.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We drilled 244 wells (85.30 net wells) in 2006 compared to 192 wells (72.63 net wells) in 2005. Our total capital expenditures for oil and natural gas exploration and acquisitions, excluding the increases in provision for plugging liability in 2006 of $10.2 million, totaled $340.0 million. Based on current prices, we plan to drill an estimated 270 wells in 2007 and estimate our total capital expenditures for oil and natural gas exploration and acquisitions to be approximately $326.0 million excluding acquisitions. Whether we are able to drill the full number of wells we are planning on drilling is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, prices for oil and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners. To provide for the completion of wells, we have committed to purchase $9.4 million of casing and tubing in the first six months of 2007.

On May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition were included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. Included in this acquisition was all of Brighton's oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and results of operations from this acquisition are included in the statement of income beginning October 1, 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

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.

At the end of the second quarter of 2005, in response to the difficulty in retaining qualified labor, we increased wages in our drilling areas that had not already received increases in the fourth quarter of 2004. We also increased wages in one of our divisions starting in the second quarter of 2006 and again at the end of the second quarter for all but two of our divisions. To date, these efforts have allowed us to meet our labor requirements. However, if demand for drilling rigs strengthens, shortages of experienced personnel may limit our ability to operate our drilling rigs at or above the 97% and 96% utilization rates we achieved in 2005 and 2006, respectively.

We currently do not have any shortages of drill pipe and drilling equipment. Because of the potential for future shortages in the availability of new drill pipe, at December 31, 2006, we had commitments to purchase approximately $42.9 million of drill pipe and drill collars in 2007. We have committed to purchase $0.6 million of additional drilling rig components which we will use to build new drilling rigs.

Most of our drilling rig fleet is used to drill natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we can charge for our contract drilling services. In January 2006, the average dayrate for the 112 drilling rigs we then owned was $16,719 per day with a 97% utilization rate. In December 2006, our average dayrate for the 117 drilling rigs that we then owned was $19,930 with an 88% utilization rate. In 2006, our average dayrate was $18,767 per day compared to $12,431 per day in 2005. The average number of our drilling rigs used in 2006 was 109.0 drilling rigs (96%) compared with 102.1 drilling rigs (97%) for 2005. Based on the average utilization of our drilling rigs during 2006, a $100 per day change in dayrates has a $10,900 per day ($4.0 million 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 subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services contain the same terms and rates as the contracts we use with unrelated third parties for comparable type projects. During 2006 and 2005, we drilled 72 and 53 wells, respectively, for our exploration and production subsidiary. The profit received by our contract drilling segment of $22.2 million and $8.6 million during 2006 and 2005, 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. In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired drilling rig was modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May we began moving a 1,500 horsepower drilling rig to our Rocky Mountain Division following completion of its construction in the first quarter of 2006 for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two new 1,500 horsepower drilling rigs for a total of $15.2 million of which $4.6 million was paid before the second quarter of 2006 and the balance of $10.6 million was paid at delivery of the rigs. An additional $3.0 million of modifications were made to the rigs before the rigs were placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower rig for approximately $9.5 million which was moved into our Rocky Mountain Division. In the last half of 2006 we completed construction of a 750 horsepower rig for approximately $4.5 million.

During 2006 we paid $4.5 million for the purchase of major components to construct two 1,500 horsepower drilling rigs. The rigs should be placed in service in the first and second quarters of 2007.

For our contract drilling operations during 2006, we incurred $170.5 million in capital expenditures, which includes the 6 drilling rigs acquired or built in 2006 and $17.9 million of additional goodwill from the third and final year of the SerDrilco acquisition earn-out. For 2007, we have budgeted capital expenditures of approximately $131.0 million for our contract drilling operations.

Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiary. Superior is a mid-stream company engaged primarily in the buying and selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, six operating processing plants, 37 active gathering systems and 600 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas and has been in business since 1996. This subsidiary enhances our ability to gather and market not only our own natural gas but also that owned by third parties and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During 2006, Superior purchased $8.0 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $5.3 million. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas exploration operations has been eliminated in our consolidated condensed financial statements. In 2005, we eliminated intercompany revenues of $6.7 million of natural gas and $95,000 of natural gas liquids and in 2004, $1.8 million of natural gas and $53,000 of natural gas liquids.

Mid-Stream Acquisitions. In September 2006, we closed the acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in the company's statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

During 2006, Superior incurred $42.9 million in capital expenditures, including tangible and intangible assets acquired through acquisitions, as compared to $21.8 million in 2005. For 2007, we have budgeted capital expenditures of approximately $25.0 million for Superior. Our focus is on growing this segment through the construction of new facilities or acquisitions.

Superior gathered 247,537 MMBtu per day in 2006 compared to 142,444 MMBtu per day in 2005 and processed 31,833 MMBtu per day in 2006 compared to 30,613 MMBtu per day in 2005. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 141,645 MMBtu and 68,297 MMBtu per day in 2006 and 2005, respectively.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner of 12 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's 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 2006, 2005 and 2004, the total we received for all of these fees was $1.3 million, $1.0 million and $0.7 million, respectively. We expect that these fees for 2007 will be comparable to those in 2006. 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. A gain before income taxes of $3.8 million was recognized in other revenues from this sale during the third quarter of 2004. 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 identify those 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. In the following discussion we will attempt to explain the nature of these estimates, assumptions and judgments, as well as the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

The following table lists the critical accounting policies, 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 • Valuation of unproved properties • Estimates of future development costs	• Oil and gas properties • Accumulated DD&A • Provision for DD&A • Impairment of proved and unproved properties • Long-term debt and interest expense
Accounting for asset retirement obligations for oil and gas properties	• Cost estimates related to the plugging and abandonment of wells • Timing of cost incurred	• 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
Accounting for value of stock compensation awards	• Estimates of stock volatility • Estimates of expected life of awards granted • Estimates of rates of forfeitures	• Oil and gas properties • Shareholder's equity • Operating expenses

Significant Estimates and Assumptions

The determination and valuation of our oil and natural gas reserves is a very subjective process. It entails estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The degree of accuracy of these estimates depends on a number of factors, including, the quality and availability of geological and engineering data, the precision of the interpretations of that data, and individual judgments based on experience and training. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our oil and natural gas reserves. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 80% of the total proved discounted future net income based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by us as of December 31, 2006.

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	Less 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 oil and natural gas 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 influenced 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 is greater than the projected revenues from the oil and natural gas reserves). But more significantly, the estimated present value of the future cash flows from our 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 the pricing we use be tied to the price we received for our 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. For example, based on our year end 2006 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 30,000 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 754,000 Mcf. Estimated future cash flows discounted at 10% before income taxes would change by $25.3 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 our DD&A rate. If reserve estimates for a property or group of properties are revised downward in the future, 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. Based on our 2006 production level of 52,889,000 equivalent Mcf, a 5% decline in the amount of our 2006 oil and natural gas reserves would increase our DD&A rate by $0.11 per Mcfe and would decrease pre-tax income by $5.8 million annually. A 5% increase in the amount of our 2006 oil and natural gas reserves would decrease our DD&A rate by $0.10 per Mcfe and would increase pre-tax income by $5.3 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 (using a 10% discount rate) of the estimated future net revenues from our proved reserves, based on period-end oil and natural gas prices adjusted for any 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 required to write-down the excess amount. 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, 2006 ($5.27 per Mcf for natural gas and $61.05 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 the future.

We use the sales method for recording natural gas sales. This method allows for the 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. The expenses relating to the wells in which we have an imbalance are not material.

On January 1, 2003, we adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 established an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of assets having a long life. In our case, when the reserves in each of our oil or gas wells deplete or otherwise become uneconomical, we are required to incur costs to plug and abandon the wells. These costs 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 the 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 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 our estimates.

Drilling equipment, transportation equipment, gas gathering and processing systems 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 that these carrying amounts 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. The 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.

In our contract drilling operations, because we do not bear the risk of completion of a well being 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 2006, we did not drill any wells under turnkey or footage 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. Increases in these prices increase the demand for our contract drilling rigs and services. This increase in demand in turn affects 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 six years natural gas and oil prices have been more volatile, and during periods of higher demand for our drilling rigs we have experienced increases in labor costs as well as the costs of services to support our drilling rigs. During this same period, when oil and natural gas 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. Increases in dayrates for drilling rigs also increase the cost of our oil and natural gas properties. With an overall increase in drilling activity throughout the industry, costs for goods and services related to both our oil and natural gas exploration segment, and our mid-stream segment have been increasing. These conditions may limit our ability to realize increases in our operating profits. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates, the prices we receive for our oil and natural gas and the rates we receive for gathering and processing natural gas.

NEW ACCOUNTING PRONOUNCEMENTS

Before January 1, 2006, we accounted for our stock-based compensation plans under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment", (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification, will be recognized in our financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights. The value of restricted stock grants is based on the closing stock price on the date of the grant. Prior to the adoption of FAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. In accordance with the implementation of FAS 123(R) we expensed \$0.8 million in the contract drilling segment, \$0.6 million in the oil and natural gas segment and \$1.7 million to corporate general and administrative expense, for a total of \$3.1 million, in 2006 and capitalized \$0.7 million as a part of geological and geophysical costs.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, on adoption of FAS 123(R) we eliminated \$2.2 million of unearned compensation cost associated with restricted stock and reduced additional paid-in capital by the same amount on our condensed consolidated balance sheet.

The remaining unrecognized compensation cost related to unvested awards at December 31, 2006 is approximately \$4.0 million with \$0.7 million of that amount to be capitalized. The weighted average period of time over which this cost will be recognized is less than one year. If we had applied the fair value provisions of FAS 123(R) to stock-based employee compensation in 2005, net income and earnings per share would have been reduced by approximately \$2.1 million and \$0.05, respectively and in 2004 by approximately \$1.7 million and \$0.04, respectively.

Under the provision of FAS 123(R), tax deductions associated with our stock based compensation plans in excess of the compensation cost recognized are recorded as an increase to additional paid in capital and reflected as a financing cash flow in the statement of cash flows. The adoption of FAS 123(R) did not have a material impact on our consolidated statements of cash flows for the twelve month period ended December 31, 2006.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS No. 109, "Accounting for Income Taxes". FIN 48 refers to "tax positions" as positions taken in a previously filed tax return or positions expected to be taken in a future tax return that are reflected in measuring current or deferred income tax assets and liabilities reported in the financial statements. FIN 48 further clarifies a tax position to include the following:

- a decision not to file a tax return in a particular jurisdiction for which a return might be required;
- an allocation or a shift of income between taxing jurisdictions;
- the characterization of income or a decision to exclude reporting taxable income in a tax return; or
- a decision to classify a transaction, entity, or other position in a tax return as tax exempt.

FIN 48 clarifies that a tax benefit may be reflected in the financial statements only if it is "more likely than not" that we will be able to sustain the tax return position, based on its technical merits. If a tax benefit meets this criterion, it should be measured and recognized based on the largest amount of benefit that is cumulatively greater than 50% likely to be realized. This is a change from current practice, whereby companies may recognize a tax benefit only if it is probable a tax position will be sustained.

FIN 48 also requires that we make qualitative and quantitative disclosures, including a discussion of reasonably possible changes that might occur in unrecognized tax benefits over the next 12 months; a description of open tax years by major jurisdictions; and a roll-forward of all unrecognized tax benefits, presented as a reconciliation of the beginning and ending balances of the unrecognized tax benefits on an aggregated basis.

This statement became effective for us on January 1, 2007. While we continue to evaluate this standard, we do not believe it will have a material effect on our statement of income, financial condition or cash flows.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)." According to the provisions of EITF 06-3:

- taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and
- that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies." In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

EITF 06-3 should be applied to financial reports for interim and annual reporting periods beginning after December 15, 2006. Because the provisions of EITF 06-3 require only the presentation of additional disclosures, we do not expect the adoption of EITF 06-3 to have an effect on our statements of income, financial condition or cash flows.

In September 2006, the FASB issued FAS No. 157, "Fair Value Measurements" (FAS No. 157). FAS No. 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of FAS No. 157 on our statement of income, financial condition and cash flows.

RESULTS OF OPERATIONS

2006 versus 2005

Provided below is a comparison of selected operating and financial data between the years of 2006 and 2005:

	2006	2005	Percent Change
Total Revenue	$1,162,385,000	$885,608,000	31%
Net Income	$ 312,177,000	$212,442,000	47%
Drilling:			
Revenue	$ 699,396,000	$462,141,000	51%
Operating costs excluding depreciation	$ 313,882,000	$266,472,000	18%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	109.0	102.1	7%
Average dayrate on daywork contracts	$ 18,767	$ 12,431	51%
Depreciation	$ 51,959,000	$ 42,876,000	21%
Oil and Natural Gas:			
Revenue	$ 357,599,000	$318,208,000	12%
Operating costs excluding depreciation, depletion and amortization	$ 81,120,000	$ 60,779,000	33%
Average natural gas price (Mcf)	$ 6.17	$ 7.64	(19)%
Average oil price (Bbl)	$ 55.11	$ 50.14	10%
Natural gas production (Mcf)	44,169,000	34,058,000	30%
Oil production (Bbl)	1,453,000	1,084,000	34%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.04	$ 1.65	24%
Depreciation, depletion and amortization	$ 108,124,000	$ 67,282,000	61%
Mid-Stream Operations:			
Revenue	$ 101,863,000	$100,464,000	1%
Operating costs excluding depreciation and amortization	$ 88,834,000	$ 92,467,000	(4)%
Depreciation and amortization	$ 6,247,000	$ 3,279,000	91%
Gas gathered—MMBtu/day	247,537	142,444	74%
Gas processed—MMBtu/day	31,833	30,613	4%
General and Administrative Expense	$ 18,690,000	$ 14,343,000	30%
Interest Expense	$ 5,273,000	$ 3,437,000	53%
Income Tax Expense	$ 176,079,000	$122,231,000	44%
Average Interest Rate	5.9%	4.8%	23%
Average Long-Term Debt Outstanding	$ 135,617,000	$107,161,000	27%

Industry demand for our drilling rigs increased throughout 2005 and remained strong during the first three quarters of 2006 before beginning to soften in the last half of the fourth quarter. Drilling revenues increased $237.3 million or 51% in 2006 versus 2005. During 2005 we added 12 drilling rigs from acquisition and construction and during 2006 we added six drilling rigs primarily through construction and we lost one rig to fire in January 2006. The 17 net additional drilling rigs added during the two years helped increase our 2006 drilling revenues by approximately 27%. The increase in utilization from these additional drilling rigs and the increase in utilization of our previously owned drilling rigs represented 13% of the increase in our drilling revenues while increases in dayrates and mobilization fees accounted for the remaining 87% of the increase. Our average dayrate in 2006 was 51% higher than in 2005. Opportunities to increase drilling rig revenues through economical acquisition of existing drilling rigs is expected to be limited in 2007, because the relatively high demand for drilling rigs during the past several years has resulted in higher purchase costs. In addition, with lower commodity prices and the uncertainty of any future increases, drilling rig revenues may experience declines in 2007 compared to 2006 levels.

Drilling operating costs increased $47.4 million or 18% over 2005. Thirty-eight percent of this increase resulted from the 17 drilling rigs placed in service during 2005 and 2006 and increased utilization of our previously owned drilling rigs, while increases in operating cost per day accounted for the remaining 62% of the increase. Operating cost per day increased $736 in 2006 when compared with 2005. A majority of the increase was attributable to costs directly associated with the drilling of wells with increases in labor cost the primary reason for the increase. Demand for rigs softened in the fourth quarter of 2006 as operators reevaluated their drilling programs in response to the declines in natural gas prices late in the third quarter of 2006. We did not drill any turnkey or footage wells in 2006 and we had one footage well in 2005. Contract drilling depreciation increased $9.1 million or 21%. The addition of the 17 net drilling rigs placed in service during 2005 and 2006 increased depreciation $4.1 million or 10% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

Our 2006 oil and natural gas revenues increased $39.4 million or 12% as compared to 2005. A 30% increase in equivalent oil and natural gas volumes along with increased oil prices accounted for the increase while a decrease in natural gas prices partially offset the increase. Average oil prices between the comparative years increased 10% to $55.11 per barrel while natural gas prices declined 19% to $6.17 per Mcf. In 2006, natural gas production increased 30% while oil production increased 34%. The increase in oil and natural gas production came primarily from our ongoing development drilling activity, the two acquisitions completed in 2005 and from the two acquisitions completed in 2006. With the continuation of our internal drilling program and our previous acquisitions, we believe our total production for 2007 compared to 2006 will increase approximately 13%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $20.3 million or 33% in 2006 as compared to 2005. An increase in the average cost per equivalent Mcf produced represented 20% of the increase with the remaining 80% attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 74% of the increase, gross production taxes 12%, general and administrative cost directly related to oil and natural gas production 12%, and accretion in plugging liability 2%. Lease operating expenses per Mcfe increased 18% between the comparative years. Workover expenses represented 4% of the increase of lease operating expenses while the remaining 96% was primarily due to increases in the cost of goods and services and the 242 net wells added from acquisitions and drilling in 2006. Gross production taxes increased due to the increase in natural gas and oil volumes produced and the increase in oil prices between the comparative years partially offset by decreases in natural gas prices. General and administrative cost increased primarily from a 14% increase in the number of our employees. Total depreciation, depletion and amortization ("DD&A") on our oil and natural gas properties increased $40.8 million or 61%. Higher production volumes contributed to 50% of the increase and increases in the DD&A rate represented the other 50% of the increase. The increase in the DD&A rate in 2006 as compared to 2005, resulted from an 18% higher overall finding cost per equivalent Mcf. Demand for drilling rigs throughout our areas of exploration have increased the dayrates we pay to drill wells in our developmental program and higher natural gas and oil prices has caused increased sales prices for producing property acquisitions.

Our mid-stream segment is engaged primarily in the mid-stream buying and selling, gathering, processing and treating of natural gas. We operate three natural gas treatment plants and own six operating processing plants, 37 active gathering systems and 600 miles of pipeline. These operations are conducted in Oklahoma, Texas, Louisiana and Kansas. Our mid-stream revenues were $1.4 million higher in 2006 versus 2005 due to the higher volumes transported offset by lower natural gas prices on volumes sold. Gas gathering volumes per day in 2006 were 74% higher as compared to 2005 while gas processing volumes per day increased 4%. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 141,645 MMBtu and 68,297 MMBtu per day during 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet is accepting the delivered natural gas unprocessed, which offset most of the increase we had in processed natural gas between the years. Operating costs decreased 4% in 2006 compared with 2005 due a 19% decrease in prices paid for natural gas purchased. The decrease in natural gas purchases was partially offset by an 87% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas transported. The 91% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation associated with tangible assets acquired during the comparative periods and the $0.9 million amortization of intangible assets associated with the acquisition of Berkshire Energy LLC.

General and administrative expense increased $4.3 million or 30%. The increase was primarily from increases in the number of employees associated with the growth of the company and $1.7 million of additional expense incurred after the implementation of Financial Accounting Standards (FAS) No. 123(R) "Share-Based Payment" which requires the recognition of expense related to the value of stock options and restricted stock granted over their vesting period.

Total interest expense increased 53% between the comparative years. Our average debt outstanding was higher in 2006 as compared 2005 because of the capital expenditures made in the fourth quarter of 2005 and throughout 2006. The increase in interest rates accounted for 54% of the interest expense increase while the increase in average debt outstanding accounted for approximately 46% of the increase. Settlements of our interest rate swap partially offset the increase in our bank interest rate. Associated with our increased level of development of our oil and natural gas properties and the construction of additional drilling rigs and natural gas gathering systems, we capitalized $3.5 million of interest in 2006 compared to $2.2 million in 2005.

Our 2006 income tax expense increased $53.9 million or 44% over 2005 due primarily to our increase in income before income taxes. Our effective tax rate for 2006 was 36.1% versus 36.5% in 2005. The decrease in the effective tax rate resulted primarily from decreased state tax expense associated with increased operations in states with lower income tax rates. As a result of the increase in our pre-tax income and the prior use of our net operating loss carryforwards, the portion of our taxes reflected as current income tax expense increased in 2006 when compared with 2005. Current income tax expense for 2006 and 2005 was $112.8 million and $64.6 million, respectively.

2005 versus 2004

Provided below is a comparison of selected operating and financial data for the year of 2005 versus the year of 2004:

	2005	2004	Percent Change
Total Revenue	$885,608,000	$519,203,000	71%
Net Income	$212,442,000	$ 90,275,000	135%
Drilling:			
Revenue	$462,141,000	$298,204,000	55%
Operating costs excluding depreciation	$266,472,000	$210,912,000	26%
Percentage of revenue from daywork contracts	100%	100%	—%
Average number of drilling rigs in use	102.1	88.1	16%
Average dayrate on daywork contracts	$ 12,431	$ 8,937	39%
Depreciation	$ 42,876,000	$ 33,659,000	27%
Oil and Natural Gas:			
Revenue	$318,208,000	$185,017,000	72%
Operating costs excluding depreciation, depletion and amortization	$ 60,779,000	$ 41,303,000	47%
Average natural gas price (Mcf)	$ 7.64	$ 5.42	41%
Average oil price (Bbl)	$ 50.14	$ 33.20	51%
Natural gas production (Mcf)	34,058,000	27,149,000	25%
Oil production (Bbl)	1,084,000	1,048,000	3%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.65	$ 1.41	17%
Depreciation, depletion and amortization	$ 67,282,000	$ 47,517,000	42%

	2005	2004	Percent Change
Mid-Stream Operations:			
Revenue	$100,464,000	$29,717,000	238%
Operating costs excluding depreciation	$ 92,467,000	$27,018,000	242%
Depreciation	$ 3,279,000	$ 982,000	234%
Gas gathered—MMBtu/day	142,444	33,147	330%
Gas processed—MMBtu/day	30,613	13,412	128%
General and Administrative Expense	$ 14,343,000	$11,987,000	20%
Interest Expense	$ 3,437,000	$ 2,695,000	28%
Income Tax Expense	$122,231,000	$53,458,000	129%
Average Interest Rate	4.8%	2.8%	71%
Average Long-Term Debt Outstanding	$107,161,000	$83,121,000	29%

Industry demand for our drilling rigs increased throughout 2004 and 2005 as natural gas prices continued to remain above $4.50 per Mcf. Drilling revenues increased $163.9 million or 55% in 2005 versus 2004. In July 2004, we added nine drilling rigs with the acquisition of Sauer Drilling Company, and with the Texas Wyoming Drilling, Inc. acquisition, we added six drilling rigs on August 31, 2005, and one drilling rig on October 13, 2005. In addition to the Sauer drilling rigs and the Texas Wyoming drilling rigs, we also placed seven additional drilling rigs into service since the second quarter of 2004. The 23 additional drilling rigs increased our 2005 drilling revenues by approximately 20%. The increase in revenue from these additional drilling rigs and the increase in utilization of our previously owned drilling rigs represented 28% of the increase in our drilling revenues. Increases in dayrates and mobilization fees accounted for 72% of the increase in total drilling revenues. Our average dayrate in 2005 was 39% higher than in 2004.

Drilling operating costs increased $55.6 million or 26% over 2004. The increase in operating costs from the 23 drilling rigs placed in service since the second quarter of 2004 and increased utilization of our previously owned drilling rigs represented 59% of the increase in operating cost. Increases in operating cost per day accounted for 41% of the increase in total operating costs. Operating cost per day increased $610 in 2005 when compared with 2004. A majority of the increase was attributable to costs directly associated with the drilling of wells with increases in labor cost the primary reason for the increase. Indirect drilling costs made up most of the remainder of the increase in per day costs and consisted primarily of indirect labor costs, property taxes, safety related expenses and repairs.

We did not drill any turnkey or footage wells in 2004 and we had one footage well in 2005. Contract drilling depreciation increased $9.2 million or 27%. The addition of the 23 drilling rigs placed in service since the second quarter of 2004 increased depreciation $4.2 million or 13% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

Our 2005 oil and natural gas revenues increased $133.2 million or 72% as compared to 2004. Increased oil and natural gas prices accounted for 71% of this increase while increased production volumes accounted for 29% of the increase.

Oil and natural gas operating cost increased $19.5 million or 47% in 2005 as compared to 2004. Cost directly related to the production of producing property acquisitions in 2005 represented 6% of the increase while 94% came from production costs related to wells we drilled in 2005 and increases in production costs from previously drilled wells. Lease operating expenses represented 45% of the increase, gross production taxes 42% and general and administrative cost directly related to oil and natural gas production 13%. Lease operating expenses per Mcfe increased 13% between the comparative years. Workover expenses represented 68% of the increase while the remaining 32% of the increase is primarily due to increases in the cost of goods and services. Gross production taxes increased due to the increase in natural gas volumes produced and the increase in commodity prices between the comparative quarters.

DD&A on our oil and natural gas properties increased $19.8 million or 42%. Higher production volumes is attributed to 51% of the increase and increases in the DD&A rate represented 49% of the increase. The increase in the DD&A rate in 2005 resulted from 14% higher overall finding cost per equivalent Mcf in 2005 versus 2004.

In July 2004, we consolidated and increased our mid-stream 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 have been consolidated with Superior's operations. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates two natural gas treatment plants, five processing plants, 36 active gathering systems and 500 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 $0.6 million net of income tax in 2004. 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 mid-stream revenues, operating expenses and depreciation were $70.7 million, $65.4 million and $2.3 million higher, respectively, all due to the Superior acquisition.

General and administrative expense increased $2.4 million or 20%. The increase was primarily attributable to overall increases in personnel costs associated with a 13% increase in the number of employees and a 16% increase in insurance costs.

Total interest expense increased 28% between the comparative years. Our average debt outstanding was higher in 2005 as compared 2004 due to the acquisition of Strata Drilling, L.L.C., the Texas Wyoming drilling rigs and the two oil and natural gas acquisitions. Average debt outstanding accounted for approximately 24% of the interest expense increase with 8% of the increase resulting from the periodic settlements of an interest rate swap and 68% resulting from an increase in average interest rates charged on our bank debt. Associated with our increased level of development of oil and natural gas properties and the construction of additional drilling rigs and natural gas gathering systems, we capitalized $2.2 million of interest in 2005. No interest was capitalized in 2004.

Our 2005 income tax expense increased $68.8 million or 129% over 2004 due primarily to our increase in income before income taxes. Our effective tax rate for 2005 was 36.5% versus 37.3% in 2004. The decrease in the effective tax rate resulted primarily from the reduction of a deduction relating to domestic production activities as provided by the American Jobs Creation Act. With our increase in pre-tax income and the utilization of a majority of our net operating loss carryforwards having been utilized in prior periods, the portion of our taxes reflected as current income tax expense increased in 2005 when compared with 2004. Current income tax expense for 2005 and 2004 was $64.6 million and $4.9 million, respectively.

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

Our operations are exposed to market risks primarily as a result of changes in the prices for natural gas and oil and interest rates.

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil and natural gas production. The prices we receive are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, these prices 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 2006 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $344,000 per month ($4.1 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $113,000 per month ($1.4 million 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 hedged 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 MD&A 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 credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. In February 2005, we entered into an interest rate swap to help manage our exposure to 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 2006 average outstanding long-term debt, a 1% increase in our floating interest rate would reduce our annual pre-tax cash flow by approximately $0.9 million.

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

Index to Financial Statements
Unit Corporation and Subsidiaries

Management's Report on Internal Control over Financial Reporting

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.

The company's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2006. 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 their assessment, the company's management concluded that, as of December 31, 2006, 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, 2006, as stated in its report which follows.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Unit Corporation:

We have completed integrated audits of Unit Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, 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 accompanying consolidated balance sheets and the related consolidated statements of income, changes in shareholders' equity and cash flows present fairly, in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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.

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, 2006 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, 2006, 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.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 1, 2007

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2006	As of December 31, 2005
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 589	$ 947
Restricted cash	18	268
Accounts receivable (less allowance for doubtful accounts of $1,600 and $1,612)	200,415	199,765
Materials and supplies	18,901	14,108
Prepaid expenses and other	13,017	8,597
Total current assets	232,940	223,685
Property and Equipment:		
Drilling equipment	781,190	626,913
Oil and natural gas properties, on the full cost method:		
Proved properties	1,330,010	995,119
Undeveloped leasehold not being amortized	53,687	38,421
Gas gathering and processing equipment	85,339	60,354
Transportation equipment	20,749	17,338
Other	17,082	12,935
	2,288,057	1,751,080
Less accumulated depreciation, depletion, amortization and impairment	735,394	575,410
Net property and equipment	1,552,663	1,175,670
Goodwill	57,524	39,659
Other Intangible Assets, Net	17,087	—
Other Assets	13,882	17,181
Total Assets	$1,874,096	$1,456,195
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 92,125	$ 109,621
Accrued liabilities	52,166	32,819
Income taxes payable	2,956	16,941
Contract advances	5,061	5,548
Current portion of other liabilities (Note 4)	8,634	7,583
Total current liabilities	160,942	172,512
Long-Term Debt (Note 4)	174,300	145,000
Other Long-Term Liabilities (Note 4)	55,741	41,981
Deferred Income Taxes (Note 5)	325,077	259,740
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, 175,000,000 and 75,000,000 shares authorized, 46,283,990 and 46,178,162 shares issued, respectively	9,257	9,236
Capital in excess of par value	333,833	328,037
Accumulated other comprehensive income (net of tax of $789 and $289, respectively)	1,339	485
Unearned compensation—restricted stock	—	(2,226)
Retained earnings	813,607	501,430
Total shareholders' equity	1,158,036	836,962
Total Liabilities and Shareholders' Equity	$1,874,096	$1,456,195

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

UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2006	2005	2004
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 699,396	$462,141	$298,204
Oil and natural gas	357,599	318,208	185,017
Gas gathering and processing	101,863	100,464	29,717
Other	3,527	4,795	6,265
Total revenues	1,162,385	885,608	519,203
Expenses:			
Contract drilling:			
Operating costs	313,882	266,472	210,912
Depreciation	51,959	42,876	33,659
Oil and natural gas:			
Operating costs	81,120	60,779	41,303
Depreciation, depletion and amortization	108,124	67,282	47,517
Gas gathering and processing:			
Operating costs	88,834	92,467	27,018
Depreciation and amortization	6,247	3,279	982
General and administrative	18,690	14,343	11,987
Interest	5,273	3,437	2,695
Total expenses	674,129	550,935	376,073
Income Before Income Taxes	488,256	334,673	143,130
Income Tax Expense:			
Current	112,812	64,565	4,866
Deferred	63,267	57,666	48,592
Total income taxes	176,079	122,231	53,458
Equity in Earnings of Unconsolidated Investments, (Net of Income Tax of $372 in 2004)	—	—	603
Net Income	$ 312,177	$212,442	$ 90,275
Net Income Per Common Share:			
Basic	$ 6.75	$ 4.62	$ 1.97
Diluted	$ 6.72	$ 4.60	$ 1.97

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, 2004, 2005 and 2006

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income	Unearned Compensation-Restricted Stock	Retained Earnings	Total
	(In thousands except per share amounts)					
Balances, January 1, 2004	$9,117	$307,938	$ —	$ —	$198,713	$ 515,768
Comprehensive income:						
Net Income	—	—	—	—	90,275	90,275
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
Total comprehensive income	—	—	—	—	—	90,275
Activity in employee compensation plans (159,907 shares)	32	2,194	—	—	—	2,226
Balances, December 31, 2004	9,149	310,132	—	—	288,988	608,269
Comprehensive income:						
Net Income	—	—	—	—	212,442	212,442
Other comprehensive income (net of tax of $1,610 and $1,899):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	(3,072)	—	—	(3,072)
Adjustment reclassification—derivative settlements	—	—	3,557	—	—	3,557
Total comprehensive income	—	—	—	—	—	212,927
Activity in employee compensation plans (186,710 shares)	38	5,954	—	(2,226)	—	3,766
Issuance of 246,053 shares of common stock for acquisition	49	11,951	—	—	—	12,000
Balances, December 31, 2005	9,236	328,037	485	(2,226)	501,430	836,962
Comprehensive income:						
Net Income	—	—	—	—	312,177	312,177
Other comprehensive income (net of tax of $202 and $701):						
Change in value of cash flow derivative instruments used as cash flow hedges	—	—	1,188	—	—	1,188
Adjustment reclassification—derivative settlements	—	—	(334)	—	—	(334)
Total comprehensive income	—	—	—	—	—	313,031
Activity in employee compensation plans (105,217 shares)	21	5,796	—	2,226	—	8,043
Balances, December 31, 2006	$9,257	$333,833	$ 1,339	$ —	$813,607	$1,158,036

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,		
	2006	2005	2004
		(In thousands)	
Cash Flows From Operating Activities:			
Net Income	$ 312,177	$ 212,442	$ 90,275
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	167,066	114,294	83,025
Equity in net earnings of unconsolidated investments	—	—	(976)
Gain on disposition of assets	(1,275)	(2,655)	(4,386)
Employee stock compensation plans	6,785	3,488	1,632
Bad debt expense	—	—	400
Plugging liability accretion	1,492	953	860
Other	30	—	(111)
Deferred tax expense	63,267	57,666	48,964
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	7,233	(106,585)	(14,579)
Cost of uncompleted drilling contracts	(134)	(109)	86
Materials and supplies	(4,793)	(1,054)	(5,031)
Prepaid expenses and other	(1,994)	(845)	(1,324)
Accounts payable	(32,577)	15,897	(1,380)
Accrued liabilities	(10,012)	21,056	5,539
Contract advances	(563)	3,223	216
Net cash provided by operating activities	506,702	317,771	203,210
Cash Flows From Investing Activities:			
Capital expenditures	(423,428)	(254,450)	(165,950)
Producing property and other acquisitions	(122,915)	(136,413)	(148,076)
Proceeds from disposition of property and equipment	6,796	8,722	9,975
(Acquisition) disposition of other assets	(1,176)	(2,855)	2,079
Net cash used in investing activities	(540,723)	(384,996)	(301,972)
Cash Flows From Financing Activities:			
Borrowings under line of credit	287,300	268,200	211,200
Payments under line of credit	(258,000)	(218,700)	(116,100)
Net payments on notes payable and other long-term debt	—	273	(2,100)
Proceeds from exercise of stock options	803	1,201	486
Tax benefit from stock options	532	—	—
Book overdrafts (Note 1)	3,028	16,533	5,343
Net cash provided by financing activities	33,663	67,507	98,829
Net Increase (Decrease) in Cash and Cash Equivalents	(358)	282	67
Cash and Cash Equivalents, Beginning of Year	947	665	598
Cash and Cash Equivalents, End of Year	$ 589	$ 947	$ 665
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Interest	$ 9,134	$ 4,798	$ 2,520
Income taxes	$ 125,144	$ 47,276	$ 4,787

See Note 2 for non-cash financing and 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, the North Texas Barnett Shale 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. Unit provides land contract drilling services for a wide range of customers using the drilling rigs, which it owns and operates. Mid-stream operations are performed in Oklahoma, Texas, Louisiana and Kansas.

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 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. The duration of all three types of contracts typically range from 20 to 90 days. At December 31, 2006, 29 of its daywork contracts had durations which ranged from 6 months to two years. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

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, 2006 and 2005, book overdrafts of $27.7 million and $24.6. 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 starting at 15 years, 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 acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to the drilling segment. In 2005, the carrying amount of goodwill increased by $9.1 million resulting from the $1.1 million of goodwill acquired in the acquisition of a subsidiary of Strata Drilling, L.L.C. , $7.6 million for the 2005 earn-out as provided for in the purchase agreement relating to the SerDrilco Incorporated acquisition and a $0.4 million adjustment to the Sauer Drilling Company purchase price. In 2006, the carrying amount of goodwill increased by $17.9 million from additional goodwill recorded for the final earn-out due under the SerDrilco Incorporated acquisition. The acquisitions are more fully discussed in Note 2. Goodwill of $10.3 million is expected to be deductible for tax purposes.

Intangible Assets. Intangible assets are capitalized and amortized over the estimated period benefited. Such amounts are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Amortization of $0.9 million was expensed in 2006. Amortization of $3.3 million, $4.4 million, $3.8 million, $2.6 million and $1.2 million is expected to be expensed in 2007, 2008, 2009, 2010 and 2011, respectively.

Oil and Natural Gas Operations. Unit accounts for its oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the 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. Directly related overhead costs of $10.2 million, $7.0 million and $4.8 million were capitalized in 2006, 2005 and 2004, respectively. 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 $2.04, $1.65 and $1.41 per Mcfe in 2006, 2005 and 2004, 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 $53.7 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.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

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 2006, the contract drilling subsidiary drilled 72 wells for Unit's exploration and production subsidiary. As required by the SEC, the profit received by the contract drilling segment of $22.2 million, $8.6 million and $3.7 million during 2006, 2005 and 2004, respectively, was used to reduce the carrying value of Unit's oil and natural gas properties rather than being included in its operating profit.

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in 12 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 its share of pro-rata production from certain wells. Unit estimates its December 31, 2006 balancing position to be approximately 3.3 Bcf on under-produced properties and approximately 2.9 Bcf on over-produced properties. Unit has recorded a receivable of $0.2 million on certain wells where it 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 it believes 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. Before January 1, 2006, Unit accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, Unit adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. Unit elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Financial statements for prior periods have not been restated. Upon adoption of FAS 123(R), Unit elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Staff Position No. FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards", issued on November 10, 2005. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair value on the date of grant or modification, will be recognized in the financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and operating costs of Unit's business segments. Unit utilizes the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights. The value of restricted stock grants is based on the closing stock price on the date of the grant.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, with the adoption of FAS 123(R) we eliminated $2.2 million of unearned compensation cost associated with grants of restricted stock and reduced additional paid-in capital by the same amount on the condensed consolidated balance sheet. FAS 123(R) requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock-based compensation to be classified as financing cash inflows in Unit's statements of cash flows. Accordingly, for the year ended December 31, 2006, we recorded $0.5 million of such tax benefits from stock based compensation as provided by financing activities.

The following table illustrates the effect on net income and earnings per share if Unit had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation prior to January 1, 2006. Compensation expense included in reported net income before January 1, 2006 is Unit's matching 401(k) contribution.

	2005	2004
	(In thousands except per share amounts)	
Net Income, as Reported	$212,442	$90,275
Add Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax	1,923	1,026
Less Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(3,989)	(2,760)
Pro Forma Net Income	$210,376	$88,541
Basic Earnings per Share:		
As reported	$ 4.62	$ 1.97
Pro forma	$ 4.58	$ 1.94
Diluted Earnings per Share:		
As reported	$ 4.60	$ 1.97
Pro forma	$ 4.55	$ 1.93

In 2006, Unit recognized stock compensation expense for restricted stock awards and stock options of $3.1 million and capitalized stock compensation cost for oil and natural gas properties of $0.7 million. The tax benefit related to this stock based compensation was $0.9 million. The remaining unrecognized compensation cost related to unvested awards at December 31, 2006 is approximately $4.0 million with $0.7 million of this amount to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

The following table estimates the fair value of each option and stock appreciation rights granted during the twelve month periods ending December 31, 2006, 2005 and 2004 using the Black-Scholes model applying the estimated values presented in the table:

	Twelve Months Ended December 31,		
	2006	2005	2004
Options Granted	33,000	58,500	159,000
Stock Appreciation Rights	44,665	—	—
Estimated Fair Value (In Millions)	$ 2.1	$ 1.3	$ 3.3
Estimate of Stock Volatility	0.38 to 0.46	0.51 to 0.55	0.51 to 0.52
Estimated Dividend Yield	0%	0%	0%
Risk Free Interest Rate	4.76 to 5.00%	4.35 to 4.42%	4.40 to 4.69%
Expected Life Range Based on Prior Experience (In Years)	5 to 8	6 to 10	6 to 10

Expected volatilities are based on the historical volatility of Unit's stock. Unit uses historical data to estimate option exercise and employee termination rates within the model and aggregates groups of employees that have similar historical exercise behavior for valuation purposes. To date, Unit has not paid dividends on its stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised.

At Unit's annual meeting on May 3, 2006, Unit's shareholders approved the Unit Corporation Stock and Incentive Compensation Plan. This plan allows for the issuance of 2.5 million shares of common stock with 2.0 million shares being the maximum number of shares that can be issued as "incentive stock options." Awards under this plan may be granted in any one or a combination of the following:

- incentive stock options under Section 422 of the Internal Revenue Code;
- non-qualified stock options;
- performance shares;
- performance units;
- restricted stock;
- restricted stock units;
- stock appreciation rights;
- cash based awards; and
- other stock-based awards.

This plan also contains various limits as to the amount of awards that can be given to an employee in any fiscal year. All awards shall be subject to the minimum vesting periods, as determined by the company's Compensation Committee and included in the award agreement.

Activity pertaining to restricted stock awards granted by the company's Compensation Committee under the Unit Corporation Stock and Incentive Compensation Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2006	—	$ —
Granted	23,381	51.76
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2006	23,381	$51.76

For the restricted stock awards granted in 2006, 16,931 of the shares vest in fourths annually with the first vesting period on January 1, 2007. The remaining 6,450 shares all vest on January 1, 2008. No shares vested in 2006. The fair value of the restricted stock granted in 2006 at the grant date was $1.2 million. The aggregate intrinsic value of the 23,381 shares outstanding subject to vesting at December 31, 2006 was $1.1 million with a weighted average remaining contractual term of 1.4 years.

Activity pertaining to stock appreciation rights granted by the company's Compensation Committee under the Unit Corporation Stock and Incentive Compensation Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2006	—	$ —
Granted	44,665	51.76
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2006	44,665	$51.76

The stock appreciation rights granted in 2006 vest in thirds annually with the first vesting period on January 1, 2008. No shares vested in 2006. Fair value of stock appreciation rights at grant date in 2006 was $1.3 million. The aggregate intrinsic value of the 44,665 shares outstanding subject to vesting at December 31, 2006 was zero with a weighted average remaining contractual term of 2.0 years.

In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan. Under this plan 330,950 shares of common stock were reserved for issuance. 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, awards were granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in installments subject to certain restrictions. No shares were issued under the plan in 2004. On December 13, 2005, 38,190 shares (in the form of restricted stock awards) were granted under the plan one half of which was distributed on January 1, 2007 and the other half will vest on January 1, 2008. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan at Unit's annual meeting on May 3, 2006, no further grants will be made under this plan.

Activity pertaining to restricted stock awards granted under the Employee Stock Bonus Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2005	—	$ —
Granted	38,190	58.30
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2005	38,190	$58.30
Granted	—	—
Vested	—	—
Forfeited	(738)	58.30
Nonvested at December 31, 2006	37,452	$58.30

One half of the restricted stock awards was distributed on January 1, 2007 and the other half will vest on January 1, 2008. No shares vested in 2006. The fair value of the restricted stock granted in 2005 at the grant date was $2.2 million. The aggregate intrinsic value of the 37,452 shares outstanding subject to vesting at December 31, 2006 was $1.8 million with a weighted average remaining contractual term of 0.5 years.

Unit also has a Stock Option Plan, which provided for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The option plan permitted 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. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan, no further awards will be made under the option plan.

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2004	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
Granted	34,000	37.16
Exercised	(91,237)	16.08
Cancelled	(61,800)	25.03
Outstanding at December 31, 2005	434,713	24.14
Granted	5,000	55.83
Exercised	(57,563)	15.61
Cancelled	(800)	37.83
Outstanding at December 31, 2006	381,350	$25.81

The fair value of the stock options granted at the grant date under the Stock Option Plan in 2006, 2005 and 2004 was $0.1 million, $0.7 million and $2.9 million, respectively. The total grant date fair value of the 67,670, 79,870 and 71,770 shares vesting in 2006, 2005 and 2004 was $1.4 million, $1.5 million and $0.9 million, respectively. The intrinsic value of options exercised in 2006 was $2.4 million. Total cash received from the options exercised in 2006 was $0.7 million.

	Outstanding Options at December 31, 2006		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$3.75	34,000	2.0 years	$ 3.75
$16.69 – $19.04	111,000	5.4 years	$18.36
$21.50 – $26.28	89,510	7.0 years	$22.96
$34.75 – $37.83	141,840	8.0 years	$37.67
$53.90 – $60.32	5,000	9.3 years	$55.83

The aggregate intrinsic value of the 381,350 shares outstanding subject to option at December 31, 2006 was $8.6 million with a weighted average remaining contractual term of 6.5 years.

	Exercisable Options At December 31, 2006	
Exercise Prices	Number of Shares	Weighted Average Exercise Price
$3.75	34,000	$ 3.75
$16.69 – $19.04	91,600	$18.21
$21.50 – $26.28	49,970	$22.86
$34.75 – $37.83	49,340	$37.74

Options for 224,910, 214,803 and 226,170 shares were exercisable with weighted average exercise prices of $21.34, $17.68 and $14.46 at December 31, 2006, 2005 and 2004, respectively. The aggregate intrinsic value of shares exercisable at December 31, 2006 was $6.1 million with a weighted average remaining contractual term of 5.7 years.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan. Under the plan, on the first business day following each annual meeting of shareholders, each person who was then a member of the Board of Directors of Unit and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. In February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan, which replaced the prior plan. Under the new plan an aggregate of 300,000 shares of common stock may be issued on exercise of the stock options. Commencing with the year 2000 annual meeting, the amount granted 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. The term of each option is 10 years and cannot be increased and no stock options may be exercised during the first six months of its term except in case of death.

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2004	80,500	$16.19
Granted	24,500	28.23
Exercised	(11,000)	8.24
Outstanding at December 31, 2004	94,000	20.27
Granted	24,500	39.50
Exercised	(19,000)	17.99
Cancelled	(3,500)	39.50
Outstanding at December 31, 2005	96,000	24.93
Granted	28,000	62.40
Exercised	(3,500)	20.10
Outstanding at December 31, 2006	120,500	$33.78

The fair value of the stock options granted at the grant date under the Stock Option Plan in 2006, 2005 and 2004 was $0.7 million, $0.6 million and $0.4 million, respectively. The total grant date fair value of the 28,000, 24,500 and 24,500 shares vesting in 2006, 2005 and 2004 was $0.7 million, $0.6 million and $0.4 million, respectively. The intrinsic value of options exercised in 2006 was $0.1 million. Options totaling 28,000 vested during 2006. Total cash received from options exercised in 2006 was $0.1 million.

	Outstanding and Exercisable Options at December 31, 2006		
Exercise Prices	**Number of Shares**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**
$6.90	5,000	2.3 years	$ 6.90
$12.19 – $17.54	14,000	4.1 years	$16.20
$20.10 – $20.46	31,500	5.9 years	$20.30
$28.23 – $39.50	42,000	7.8 years	$33.87
$62.40	28,000	9.3 years	$62.40

Options for 120,500 and 96,000 shares were exercisable with weighted average exercise prices of $33.78 and $24.93 at December 31, 2006 and 2005, respectively. The aggregate intrinsic value of the 120,500 shares outstanding subject to options at December 31, 2006 was $1.8 million with a weighted average remaining contractual term of 7.0 years.

Self Insurance. Unit is self-insured for certain losses relating to workers' compensation, general liability, property damage, control of well and employee medical benefits. In addition, Unit's insurance policies contain deductibles or retentions per occurrence that range from $0.5 million for Oklahoma workers' compensation, as well as claims under Unit's occupation benefit plans, to $1.0 million for general liability and drilling rig physical damage. Unit has purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage Unit has will adequately protect it against liability from all potential consequences. If insurance coverage becomes more expensive, Unit may choose to decrease its limits and increase its deductibles rather than pay higher premiums. Following the acquisition of SerDrilco Incorporated and the creation of Unit Texas Drilling, L.L.C., Unit has elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas 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 is made at the discretion of management. No treasury stock was owned by Unit at December 31, 2006, 2005 and 2004.

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 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 2006, Chesapeake Operating, Inc. was Unit's largest drilling customer and provided 10% of Unit's total contract drilling revenues. In 2006, purchases by Eagle Energy Partners I, L.P., ONEOK and ConocoPhillips Company accounted for approximately 17%, 16% and 10% of Unit's oil and natural gas revenues, respectively. For 2005, purchases by Eagle Energy Partners I, L.P. accounted for approximately 31% of Unit's oil and natural gas revenues while purchases by Eagle Energy Partners I, L.P. accounted for 25% of Unit's 2004 oil and natural gas revenues and Cinergy Marketing & Trading LP accounted for approximately 11%. Before selling its interest on August 2, 2004, Unit owned a 16.7% interest in Eagle Energy Partners I, L.P. In addition, Unit had a concentration of cash of $4.3 million and $19.1 million at December 31, 2006 and 2005, respectively with one bank.

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

Unit periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil and natural gas production. Such instruments include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps and basic hedges with major energy derivative product specialists.

In December 2006, Unit entered into the following natural gas hedging transaction.

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	January through December of 2007
Prices	Floor of $6.00 and a ceiling of $9.60
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

This hedge for 2007 is a cash flow hedge and there is no material amount of ineffectiveness. The fair value of the hedge was recognized on the December 31, 2006 balance sheet as current derivative assets totaling $1.4 million and a gain of $0.9 million, net of tax, in accumulated other comprehensive income.

In January 2005, Unit entered into the following two natural gas collar contracts:

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.19
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC
Second Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2005
Prices	Floor of $5.50 and a ceiling of $7.30
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

In March 2005, Unit also entered into an oil collar contract covering 1,000 barrels of oil production per day. This transaction covered the period of April through December of 2005 and had a floor of $45.00 and a ceiling of $69.25 and is based on the underlying commodity price at West Texas Intermediate—NYMEX.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The natural gas collar contracts decreased our 2005 natural gas revenues by $4.1 million. Unit did not have any oil or natural gas hedging transactions outstanding at December 31, 2005.

During the first and second quarters of 2004, Unit entered into the following two natural gas collar contracts:

First Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	April through October of 2004
Prices	Floor of $4.50 and a ceiling of $6.76
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC
Second Contract:	
Production volume covered	10,000 MMBtus/day
Period covered	May through October of 2004
Prices	Floor of $5.00 and a ceiling of $7.00
Underlying commodity price	Centerpoint Energy Gas Transmission Co., East—Inside FERC

Unit also entered into an oil hedge covering 1,000 barrels of oil production per day. This transaction covered the period of February through December of 2004 and had an average price of $31.40 and is based on the underlying commodity price at West Texas Intermediate—NYMEX.

All of these hedges were cash flow hedges and there was no material amount of ineffectiveness. The natural gas collar contracts increased our 2004 natural gas revenues by $48,000. Oil revenues were reduced by $3.6 million in 2004 due to the settlement of the oil hedge. Unit did not have any hedging transactions outstanding at December 31, 2004.

In February 2005, Unit entered into an interest rate swap to help manage its exposure to possible future interest rate increases. This contract swaps $50.0 million of variable rate debt to fixed and covers the period from March 1, 2005 through January 30, 2008. The fixed rate is based on three-month LIBOR and is at 3.99%. This swap is a cash flow hedge. As a result of this interest rate swap, interest expense was increased by $0.2 million in 2005 and decreased by $0.5 million in 2006. The fair value of the swap was recognized on the December 31, 2006 balance sheet as current and non-current derivative assets totaling $0.7 million and a gain of $0.4 million, net of tax, in accumulated other comprehensive income.

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. Before January 1, 2006, Unit accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25, "Accounting for Stock Issued to Employees," and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. On January 1, 2006, Unit adopted Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment", (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. Prior to the adoption of FAS 123(R), Unit followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. In accordance with the implementation of FAS 123(R) Unit expensed $0.8 million in the contract drilling segment, $0.6 million in the oil and natural gas segment and $1.7 million to corporate general and administrative expense, for a total of $3.1 million, in 2006 and capitalized $0.7 million as a part of geological and geophysical costs.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, on adoption of FAS 123(R) the company eliminated $2.2 million of unearned compensation cost associated with restricted stock and reduced additional paid-in capital by the same amount on its condensed consolidated balance sheet.

The remaining unrecognized compensation cost related to unvested awards at December 31, 2006 is approximately $4.0 million with $0.7 million of that amount to be capitalized. The weighted average period of time over which this cost will be recognized is less than one year. If Unit had applied the fair value provisions of FAS 123(R) to stock-based employee compensation in 2005, net income and earnings per share would have been reduced by approximately $2.1 million and $0.05, respectively and for 2004 by approximately $1.7 million and $0.04, respectively.

Under the provision of FAS 123(R), tax deductions associated with Unit's stock based compensation plans in excess of the compensation cost recognized are recorded as an increase to additional paid in capital and reflected as a financing cash flow in the statement of cash flows. The adoption of FAS 123(R) did not have a material impact on our consolidated statements of cash flows for the twelve month period ended December 31, 2006.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FAS No. 109, "Accounting for Income Taxes". FIN 48 refers to "tax positions" as positions taken in a previously filed tax return or positions expected to be taken in a future tax return that are reflected in measuring current or deferred income tax assets and liabilities reported in the financial statements. FIN 48 further clarifies a tax position to include the following:

- a decision not to file a tax return in a particular jurisdiction for which a return might be required;
- an allocation or a shift of income between taxing jurisdictions;
- the characterization of income or a decision to exclude reporting taxable income in a tax return; or
- a decision to classify a transaction, entity, or other position in a tax return as tax exempt.

FIN 48 clarifies that a tax benefit may be reflected in the financial statements only if it is "more likely than not" that Unit will be able to sustain the tax return position, based on its technical merits. If a tax benefit meets this criterion, it should be measured and recognized based on the largest amount of benefit that is cumulatively greater than 50% likely to be realized. This is a change from current practice, whereby companies may recognize a tax benefit only if it is probable a tax position will be sustained.

FIN 48 also requires that Unit make qualitative and quantitative disclosures, including a discussion of reasonably possible changes that might occur in unrecognized tax benefits over the next 12 months; a description of open tax years by major jurisdictions; and a roll-forward of all unrecognized tax benefits, presented as a reconciliation of the beginning and ending balances of the unrecognized tax benefits on an aggregated basis.

This statement became effective for us on January 1, 2007. While the company continues to evaluate this standard, it does not believe it will have a material effect on its statement of income, financial condition or cash flows.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)". According to the provisions of EITF 06-3:

- taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and
- that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed under Accounting Principles Board Opinion No. 22 (as amended), "Disclosure of Accounting Policies". In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be made on an aggregate basis.

EITF 06-3 should be applied to financial reports for interim and annual reporting periods beginning after December 15, 2006. Because the provisions of EITF 06-3 require only the presentation of additional disclosures, the company does not expect the adoption of EITF 06-3 to have an effect on its statement of income, financial condition or cash flows.

In September 2006, the FASB issued FAS No. 157, "Fair Value Measurements" (FAS No. 157). FAS No. 157 establishes a common definition for fair value to be applied to US GAAP guidance requiring use of fair value, establishes a framework for measuring fair value, and expands the disclosure about such fair value measurements. FAS No. 157 is effective for fiscal years beginning after November 15, 2007. Unit is currently assessing the impact of FAS No. 157 on its statement of income, financial condition and cash flows.

NOTE 2—ACQUISITIONS

On October 13, 2006, Unit completed its acquisition of Brighton Energy, L.L.C., (Brighton) a privately owned oil and natural gas company for approximately $67.0 million. This acquisition involved all of Brighton's oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma). The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and was included in the company's statement of income starting in October 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price. The $67.0 million paid in this acquisition increased the company's basis in oil and natural gas properties by $65.4 with the remaining $1.6 million reflecting working capital.

In September 2006, Unit closed its acquisition of Berkshire Energy LLC., a private company for an adjusted purchase price of $21.7 million. The principal assets of the acquired company consist of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors, two plant compressors and associated customer contracts and relationships. As part of the acquisition, Superior acquired long-term contracts for the gathering and processing of natural gas that will flow through this gathering system, the value of which is reported as an amortizable intangible asset. The capitalized value of these contracts and associated customer relationship will be amortized over an estimated life of 7 years. The purchase had an effective date of July 31, 2006. The financial results of the acquisition were included in the Unit's statement of income from September 1, 2006 forward with the results for the period from August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price. The $21.7 million acquisition price for Berkshire Energy LLC was allocated as follows (in thousands):

Working Capital	$ 337
Processing Plant and Gathering System	3,422
Amortizable Intangible Assets	17,957
Total Consideration	$21,716

On May 16, 2006, Unit announced it had closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. This acquisition had an effective date of April 1, 2006. The $32.4 million paid in this acquisition increased the company's basis in oil and natural gas properties.

On November 16, 2005, Unit completed its acquisition of certain oil and natural gas properties from a group of private entities for an adjusted purchase price of $82.0 million in cash. The properties are located in Oklahoma, Arkansas and Texas. The effective date of this acquisition was July 1, 2005. The $82.0 million paid in this acquisition increased Unit's basis in oil and natural gas properties held under the full cost method. The results of operations for the acquired properties are included in the statement of income beginning November 1, 2005 with the results for the period from July 1, 2005 through October 31, 2005 included as part of the adjusted purchase price.

On August 31, 2005, Unit closed its acquisition of all the Texas drilling operations of Texas Wyoming Drilling, Inc., a Texas-based privately-owned company, with the exception of one drilling rig which the company subsequently acquired on October 13, 2005. The total purchase price of the acquisition, which includes seven drilling rigs, was $31.6 million, with $19.6 million paid in cash and $12.0 million in stock, representing 246,053 shares. Of the total amount, $13.3 million was paid in cash and $12.0 million was issued in stock on August 31, 2005 with the remaining $6.3 million paid in cash on October 13, 2005. Six of the drilling rigs are active in the Barnett Shale area of North Texas. Six of the seven drilling rigs are mechanical, and one is a diesel electric drilling rig. They range from 400 to 1,700 horsepower. The results of operations for the six drilling rigs acquired were included in the statement of income for the period after August 31, 2005 and the results of operations for the seventh drilling rig was included in the statement of income for the period after October 12, 2005.

The $31.6 million acquisition price for the seven drilling rigs and related equipment acquired from Texas Wyoming Drilling, Inc. was allocated as follows (in thousands):

Drilling Rigs	$26,006
Spare Drilling Equipment	896
Drill Pipe and Collars	4,098
Trucks	565
Other Vehicles	35
Total consideration	$31,600

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.

On June 15, 2005, Unit completed its acquisition of certain oil and natural gas properties from a private company for a purchase price of $23.1 million in cash. The effective date of the acquisition was April 1, 2005. The results of operations for the acquired properties were included in the statement of income beginning June 1, 2005 with the results for the period from April 1, 2005 through May 31, 2005 included as part of the purchase price. The $23.1 million paid in this acquisition increased our basis in oil and natural gas properties held under the full cost method with $0.9 million recorded in undeveloped leasehold.

On January 5, 2005, Unit acquired a subsidiary of Strata Drilling, L.L.C. for $10.5 million in cash. In this acquisition the company acquired two drilling rigs as well as spare parts, inventory, drill pipe, and other major drilling 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. The results of operations for this acquired company were are included in the statement of income for the period after January 5, 2005.

The $10.5 million paid in this acquisition was allocated as follows (in thousands):

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

On December 8, 2003, Unit acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest, L.L.C., for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to receive one-half of the cash flow in excess of $10.0 million for each of the three years following the acquisition. An additional $17.9 million, $7.6 million and $1.9 million was added to goodwill for the liability associated with the 2006, 2005 and 2004 earn-out, respectively. 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 were included in the statement of income for the period beginning after December 8, 2003.

The amounts paid for all of the company's acquisitions listed above were determined through arms-length negotiations between the parties and have been accounted for using the purchase accounting method.

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, 2006:			
Basic earnings per common share	$312,177	46,228	$ 6.75
Effect of dilutive stock options and restricted stock	—	223	(0.03)
Diluted earnings per common share	$312,177	46,451	$ 6.72
For the Year Ended December 31, 2005:			
Basic earnings per common share	$212,442	45,940	$ 4.62
Effect of dilutive stock options and restricted stock	—	249	(0.02)
Diluted earnings per common share	$212,442	46,189	$ 4.60
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

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,:

	2006	2005	2004
Options	33,000	—	127,500
Average Exercise Price	$ 61.40	$ —	$ 37.83

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

Long-term debt consisted of the following as of December 31:

	2006	2005
	(In thousands)	
Revolving Credit Facility, with Interest at December 31, 2006 and 2005 of 6.4% and 5.4%, Respectively	$174,300	$145,000
Less Current Portion	—	—
Total Long-Term Debt	$174,300	$145,000

On December 31, 2006, Unit had a $275.0 revolving credit facility. Borrowings under the credit facility are limited to a commitment amount. On October 10, 2006, Unit signed a third amendment to its credit facility which raised the commitment amount from $235.0 million to $275.0 million. Borrowings under the credit facility are limited to the commitment amount, but Unit may elect to have a smaller amount available. At January 1, 2006, Unit had elected the full $235.0 million of the commitment amount in place at that time to be available, On June 1, 2006, Unit elected to reduce the available amount to $175.0 before subsequently raising it to $200.0 million on

September 15, 2006 and to the full $275.0 million commitment amount on November 11, 2006. These elections were primarily made based on Unit's requirements to finance both natural gas gathering and producing oil and natural gas property acquisitions. Unit is charged a commitment fee of .375 of 1% on the amount available but not borrowed. Unit 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 amortized over the four year life of the agreement. During 2005 and 2006, Unit incurred additional origination, agency and syndication fees of $187,500 and $60,000, respectively while amending the credit facility and these fees are being amortized over the remaining life of the agreement. The average interest rate for 2006 was 6.3%. At December 31, 2006 and February 16, 2006, Unit's borrowings were $174.3 million and $160.5 million, respectively.

The borrowing base under the current credit facility is subject to re-determination on May 10 and November 10 of each year. The latest supported a borrowing base of $375.0 million. Each re-determination is based primarily on the sum of a percentage of the discounted future value of Unit's oil and natural gas reserves, as determined by the banks. The determination of Unit's borrowing base also includes an amount representing a small part of the value of the drilling rig fleet (limited to $20.0 million) as well as such loan value as the lenders reasonably attribute to Superior Pipeline Unit's cash flow as defined in the credit facility. The credit facility allows for one requested special re-determination of the borrowing base by either the banks or Unit between each scheduled re-determination date.

At Unit's election, any part of the outstanding debt may be fixed at a London Interbank Offered Rate (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. At December 31, 2006, $170.6 million of Unit's $174.3 million debt was subject to the LIBOR rate.

The credit facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of Unit's 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 the Unit's property, except in favor of Unit's banks.

The credit facility also requires that Unit have at the end of each quarter:

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

On December 31, 2006, Unit was in compliance with the covenants of its credit facility.

Other long-term liabilities consisted of the following as of December 31:

	2006	2005
	(In thousands)	
Separation Benefit Plans	$ 3,516	$ 2,788
Deferred Compensation Plan	2,544	2,611
Retirement Agreements	1,386	1,676
Workers' Compensation	22,157	19,394
Gas Balancing Liability	1,080	1,080
Plugging Liability	33,692	22,015
	64,375	49,564
Less Current Portion	8,634	7,583
Total Other Long-Term Liabilities	$55,741	$41,981

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities from 2007 through 2011 are $8.6 million, $179.1 million, $1.8 million, $1.8 million and $2.5 million. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2006 approximates its fair value.

The following table shows the activity for Unit's retirement obligation for plugging liability for the years ending December 31:

	2006	2005
	(In thousands)	
Plugging Liability, January 1	$22,015	$19,135
Accretion of Discount	1,490	953
Liability Incurred in the Period	4,383	2,861
Liability Settled in the Period	(270)	(151)
Revision of Estimates	6,074	(783)
Plugging Liability, December 31	33,692	22,015
Less Current Portion	760	366
Total Long-Term Plugging Liability	$32,932	$21,649

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:

	2006	2005	2004
		(In thousands)	
Income Tax Expense Computed by Applying the Statutory Rate	$170,890	$117,136	$50,437
State Income Tax, Net of Federal Benefit	8,949	8,231	4,323
Domestic Production Activities Deduction	(3,067)	(2,100)	—
Statutory Depletion and Other	(693)	(1,036)	(930)
Income tax expense	$176,079	$122,231	$53,830

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

	2006	2005
	(In thousands)	
Deferred Tax Assets:		
Allowance for losses and nondeductible accruals	$ 23,593	$ 15,633
Net operating loss carryforward	2,957	3,710
	26,550	19,343
Deferred Tax Liability:		
Depreciation, depletion and amortization	(345,746)	(275,421)
Net deferred tax liability	(319,196)	(256,078)
Current Deferred Tax Asset	5,881	3,662
Non-Current—Deferred Tax Liability	$(325,077)	$(259,740)

Realization of the deferred tax assets are 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, 2006, Unit has net operating loss carryforwards of approximately $7.8 million which expire from 2007 to 2023.

NOTE 6—EMPLOYEE BENEFIT PLANS

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 46,941, 51,938 and 56,152 shares of common stock and recognized expense of $3.7 million, $3.0 million and $1.6 million in 2006, 2005 and 2004, 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, 2006, 2005 and 2004 totaled $2.5 million, $2.6 million and $2.1 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 $1.1 million in 2006 and $0.7 million in each of the years 2005 and 2004, 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 12 oil and gas limited partnerships. Three were formed for investment by third parties and eight (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 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 2007, 2006 and 2005) 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:

	2006	2005	2004
	(In thousands)		
Contract Drilling	$617	$399	$262
Well Supervision and Other Fees	$297	$382	$259
General and Administrative Expense Reimbursement	$337	$263	$225

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.

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, L.P. 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, 2015 (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; Houston and Midland, Texas; and Denver, Colorado under the terms of operating leases expiring through May, 2010. Additionally, Unit has several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $1.2 million, $1.1 million, $1.1 million, and $0.1 million in 2007, 2008, 2009, and 2010, respectively. Total rent expense incurred by Unit was $1.3 million, $1.1 million and $0.8 million in 2006, 2005 and 2004, 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 $7,000, $4,000 and $14,000 in 2006, 2005 and 2004, respectively 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. Unit 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, Unit 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 drilling rig is on the location and the cost has been included in the direct cost of drilling the well.

Due to the potential for limited availability of new drill pipe within the industry, Unit has committed to purchase approximately $42.9 million of drill pipe and drill collars. Unit has committed to purchase $0.6 million of additional drilling rig components for the construction of new drilling rigs. To provide for the completion of wells, the company's oil and natural gas segment has committed to purchase $9.4 million of casing and tubing in the first six months of 2007.

On December 8, 2003, Unit acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest, L.L.C., for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to receive one-half of the cash flow in excess of $10.0 million for each of the three years following the acquisition. The last year of the three year earnout period is 2006 and earnouts of $17.9 million, $7.6 million and $1.9 million were earned in 2006, 2005 and 2004, respectively.

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 Exploration and Mid-Stream Operations, 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 Exploration segment is engaged in the development, acquisition and production of oil and natural gas properties and the Mid-Stream segment is engaged in the buying, selling, 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.

	2006	2005	2004
		(In thousands)	
Revenues:			
Contract drilling	$ 741,176	$483,501	$309,372
Elimination of inter-segment revenue	41,780	21,360	11,168
Contract drilling net of inter-segment revenue	699,396	462,141	298,204
Oil and natural gas exploration	357,599	318,208	185,017
Gas gathering and processing	115,146	109,652	33,358
Elimination of inter-segment revenue	13,283	9,188	3,641
Gas gathering and processing net of inter-segment revenue	101,863	100,464	29,717
Other	3,527	4,795	6,265
Total revenues	$1,162,385	$885,608	$519,203

	2006	2005	2004
		(In thousands)	
Operating Income (1):			
Contract drilling	$ 333,555	$ 152,793	$ 53,633
Oil and natural gas exploration	168,355	190,147	96,197
Gas gathering and processing	6,782	4,718	1,717
Total operating income	508,692	347,658	151,547
General and administrative expense	(18,690)	(14,343)	(11,987)
Interest expense	(5,273)	(3,437)	(2,695)
Other income (expense)—net	3,527	4,795	6,265
Income before income taxes	$ 488,256	$ 334,673	$ 143,130
Identifiable Assets (2):			
Contract drilling	$ 755,290	$ 593,328	$ 454,393
Oil and natural gas exploration	979,362	752,538	512,909
Gas gathering and processing	123,500	97,486	41,250
Total identifiable assets	1,858,152	1,443,352	1,008,552
Corporate assets	15,944	12,843	14,584
Total assets	$1,874,096	$1,456,195	$1,023,136
Capital Expenditures:			
Contract drilling	$ 170,485(3)	$ 142,242(4)	$ 98,437(5)
Oil and natural gas exploration	350,156(6)	274,597	215,074(7)
Gas gathering and processing	42,942(8)	21,796	31,785
Other	2,566	1,753	3,581
Total capital expenditures	$ 566,149	$ 440,388	$ 348,877
Depreciation, Depletion and Amortization:			
Contract drilling	$ 51,959	$ 42,876	$ 33,659
Oil and natural gas exploration	108,124	67,282	47,517
Gas gathering and processing	6,247	3,279	982
Other	736	857	867
Total depreciation, depletion and amortization	$ 167,066	$ 114,294	$ 83,025

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

(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 $17.9 million of goodwill from the third and final year of the SerDrilco earn-out agreement.

(4) Includes $1.1 million for goodwill acquired in the Strata Drilling, L.L.C. and $7.6 million for goodwill from the second year of the SerDrilco earn-out agreement.

(5) Includes $4.9 million for goodwill acquired in the Sauer acquisition and $1.9 million for goodwill from the first year of the SerDrilco earn-out agreement.

(6) Includes $10.2 million for capitalized cost relating to plugging liability recorded in 2006.

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

(8) Includes $18.0 million for capitalized intangibles.

NOTE 11—SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2006 and 2005 is as follows:

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In thousands except per share amounts)			
Year Ended December 31, 2006:				
Revenues	$282,808	$280,349	$299,894	$299,334
Gross profit (1)	$122,649	$123,642	$134,369	$128,032
Net income	$ 74,913	$ 74,817	$ 81,265	$ 81,182
Net income per common share:				
Basic (2)	$ 1.62	$ 1.62	$ 1.76	$ 1.76
Diluted	$ 1.61	$ 1.61	$ 1.75	$ 1.75
Year Ended December 31, 2005:				
Revenues	$171,580	$189,867	$231,048	$293,113
Gross profit (1)	$ 54,417	$ 66,677	$ 94,668	$131,896
Net income	$ 30,730	$ 39,614	$ 57,638	$ 84,460
Net income per common share:				
Basic (2)	$ 0.67	$ 0.86	$ 1.25	$ 1.83
Diluted	$ 0.67	$ 0.86	$ 1.25	$ 1.82

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

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

SUPPLEMENTAL INFORMATION

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

	USA	Canada	Total
		(In thousands)	
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	75,299	65	75,364
Asset retirement obligation	6,281	—	6,281
Total costs incurred	$ 215,004	$ 70	$ 215,074
2005:			
Capitalized costs:			
Proved properties	$ 994,780	$ 339	$ 995,119
Unproved properties	38,089	332	38,421
	1,032,869	671	1,033,540
Accumulated depreciation, depletion, amortization and impairment	(354,035)	(671)	(354,706)
Net capitalized costs	$ 678,834	$ —	$ 678,834
Cost incurred:			
Unproved properties acquired	$ 23,810	$ 4	$ 23,814
Proved properties acquired	106,921	—	106,921
Exploration	16,862	—	16,862
Development	125,026	47	125,073
Asset retirement obligation	1,927	—	1,927
Total costs incurred	$ 274,546	$ 51	$ 274,597
2006:			
Capitalized costs:			
Proved properties	$1,329,566	$ 444	$1,330,010
Unproved properties	53,350	337	53,687
	1,382,916	781	1,383,697
Accumulated depreciation, depletion, amortization and impairment	(461,639)	(671)	(462,310)
Net capitalized costs	$ 921,277	$ 110	$ 921,387
Cost incurred:			
Unproved properties acquired	$ 29,257	$ 5	$ 29,262
Proved properties acquired	92,278	—	92,278
Exploration	26,008	—	26,008
Development	192,316	105	192,421
Asset retirement obligation	10,187	—	10,187
Total costs incurred	$ 350,046	$ 110	$ 350,156

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2006, by the year in which such costs were incurred:

	2006	2005	2004	2003 and Prior	Total
			(In thousands)		
Undeveloped Leasehold Acquired	$24,359	$17,182	$8,280	$3,866	$53,687

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)	
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
2005:			
Revenues	$ 314,211	$332	$ 314,543
Production costs	(53,393)	(56)	(53,449)
Depreciation, depletion and amortization	(66,875)	(35)	(66,910)
	193,943	241	194,184
Income tax expense	(70,833)	(96)	(70,929)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 123,110	$145	$ 123,255
2006:			
Revenues	$ 352,264	$196	$ 352,460
Production costs	(70,853)	(16)	(70,869)
Depreciation, depletion and amortization	(107,604)	—	(107,604)
	173,807	180	173,987
Income tax expense	(62,744)	(72)	(62,816)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 111,063	$108	$ 111,171

The DD&A rate for Unit's United States properties was $2.04, $1.65 and $1.42 per equivalent Mcf in 2006, 2005 and 2004, respectively. The DD&A rate for Canada was $0.57 and $0.69 per equivalent Mcf in 2005 and 2004, respectively and no DD&A was recognized for Canada in 2006 since producing properties subject to amortization were fully depreciated.

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)			
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
2005:						
Proved developed and undeveloped reserves:						
Beginning of year	8,561	295,146	—	260	8,561	295,406
Revision of previous estimates	217	(2,461)	—	389	217	(2,072)
Extensions, discoveries and other additions	1,105	50,941	—	—	1,105	50,941
Purchases of minerals in place	1,072	43,056	—	—	1,072	43,056
Sales of minerals in place	—	—	—	(432)	—	(432)
Production	(1,084)	(33,997)	—	(61)	(1,084)	(34,058)
End of Year	9,871	352,685	—	156	9,871	352,841
Proved developed reserves:						
Beginning of year	7,030	223,351	—	260	7,030	223,611
End of year	8,454	269,223	—	156	8,454	269,379
2006:						
Proved developed and undeveloped reserves:						
Beginning of year	9,871	352,685	—	156	9,871	352,841
Revision of previous estimates	159	(2,779)	—	—	159	(2,779)
Extensions, discoveries and other additions	1,878	71,453	—	—	1,878	71,453
Purchases of minerals in place	1,150	29,067	—	—	1,150	29,067
Sales of minerals in place	(22)	(12)	—	—	(22)	(12)
Production	(1,453)	(44,151)	—	(19)	(1,453)	(44,170)
End of Year	11,583	406,263	—	137	11,583	406,400
Proved developed reserves:						
Beginning of year	8,454	269,223	—	156	8,454	269,379
End of year	9,507	307,597	—	137	9,507	307,734

(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. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 80% of the total proved discounted future net income based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by Unit as of December 31, 2006.

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 productibility 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)	
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
2005:			
Future cash flows	$3,222,106	$1,104	$3,223,210
Future production costs	(753,501)	(432)	(753,933)
Future development costs	(142,259)	—	(142,259)
Future income tax expenses	(791,906)	(146)	(792,052)
Future net cash flows	1,534,440	526	1,534,966
10% annual discount for estimated timing of cash flows	(671,149)	(134)	(671,283)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 863,291	$ 392	$ 863,683
2006:			
Future cash flows	$2,748,954	$ 719	$2,749,673
Future production costs	(763,376)	(301)	(763,677)
Future development costs	(218,749)	—	(218,749)
Future income tax expenses	(538,682)	(38)	(538,720)
Future net cash flows	1,228,147	380	1,228,527
10% annual discount for estimated timing of cash flows	(543,526)	(106)	(543,632)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 684,621	$ 274	$ 684,895

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

	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
2005:			
Sales and transfers of oil and natural gas produced, net of production costs	$(260,818)	$ (276)	$(261,094)
Net changes in prices and production costs	358,271	(478)	357,793
Revisions in quantity estimates and changes in production timing	(3,959)	1,138	(2,821)
Extensions, discoveries and improved recovery, less related costs	218,923	—	218,923
Changes in estimated future development cost	(14,281)	—	(14,281)
Previously estimated cost incurred during the period	21,330	—	21,330
Purchases of minerals in place	128,187	—	128,187
Sales of minerals in place	—	(640)	(640)
Accretion of discount	78,629	77	78,706
Net change in income taxes	(183,825)	61	(183,764)
Other—net	(182)	(86)	(268)
Net change	342,275	(204)	342,071
Beginning of year	521,016	596	521,612
End of year	$ 863,291	$ 392	$ 863,683
2006:			
Sales and transfers of oil and natural gas produced, net of production costs	$(281,411)	$ (180)	$(281,591)
Net changes in prices and production costs	(408,130)	(56)	(408,186)
Revisions in quantity estimates and changes in production timing	(4,191)	1	(4,190)
Extensions, discoveries and improved recovery, less related costs	197,897	—	197,897
Changes in estimated future development cost	(10,875)	—	(10,875)
Previously estimated cost incurred during the period	30,112	—	30,112
Purchases of minerals in place	65,531	—	65,531
Sales of minerals in place	(399)	—	(399)
Accretion of discount	131,239	51	131,290
Net change in income taxes	149,906	84	149,990
Other—net	(48,349)	(18)	(48,367)
Net change	(178,670)	(118)	(178,788)
Beginning of year	863,291	392	863,683
End of year	$ 684,621	$ 274	$ 684,895

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 $61.05 and natural gas $5.27 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.

(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, 2006.

The company's management assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006 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.*

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

In accordance with Instruction G(3) of Form 10-K, the information required by this item is incorporated herein by reference to the Proxy Statement. The Proxy Statement will be filed before the company's annual shareholders' meeting scheduled to be held on May 2, 2007, except for the information regarding the executive officers of the company. Information regarding executive officers is included in Part I of this report under the caption "Executive Officers."

The company's Code of Ethics and Business Conduct applies to all directors, officers and employees, including our Chief Executive Officer, our Chief Financial Officer and our Controller. You can find our Code of Ethics and Business Conduct on our internet site, www.unitcorp.com. We will post any amendments to the Code of Ethics and Business Conduct, and any waivers that are required to be disclosed by the rules of either the SEC or the NYSE, on our internet site.

Because our common stock is listed on the NYSE in 2006, our Chief Executive Officer was required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by the company of the corporate governance listing standards of the applicable exchange. Our Chief Executive Officer made his annual certification to that effect to the NYSE as of June 2, 2006. In addition, the company has filed, as exhibits to this Annual Report on Form 10-K, the certifications of its Chief Executive Officer and Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the SEC regarding the quality of the company's public disclosure.

Item 11. ***Executive Compensation.***

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated herein by reference to the Proxy Statement (see Item 10 above).

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

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated herein by reference to the Proxy Statement (see Item 10 above).

Item 13. ***Certain Relationships, Related Transactions and Director Independence.***

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated herein by reference to the Proxy Statement (see Item 10 above).

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

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated herein by reference to the Proxy Statement (see Item 10 above).

PART IV

Item 15. ***Exhibits, 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, 2006 and 2005
Consolidated Statements of Income for the years ended December 31, 2006, 2005 and 2004
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2004, 2005 and 2006
Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004
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, 2006, 2005 and 2004:

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).

3.3 Certificate of Amendment of Amended and Restated Certificate of Incorporation of the Company (filed as Exhibit 3.1 to Unit's Form 8-K, dated May 9, 2006 which 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).
4.2.9	Rights Agreement as amended and restated on May 18, 2005 (filed as Exhibit 4.1 to Unit's Form 8-K dated May 18, 2005, 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).
10.1.27	First Amendment to Credit Agreement dated June 13, 2005 (filed as Exhibit 10.1 to Unit's Form 8-K dated June 13, 2005, which is incorporated herein by reference).
10.1.27	Second Amendment to Credit Agreement effective November 1, 2005 (filed as Exhibit 10.1 to Unit's Form 8-K dated November 4, 2005, which is incorporated herein by reference).
10.1.28	Third Amended and Restated Security Agreement effective November 1, 2005 (filed as Exhibit 10.2 to Unit's Form 8-K dated November 4, 2005, which is incorporated herein by reference).
10.1.29	Form of Unit Corporation Restricted Stock Bonus Agreement (filed as Exhibit 10.1 to Unit's Form 8-K dated December 13, 2005, which is incorporated herein by reference).
10.1.30	Unit Corporation Stock and Incentive Compensation Plan (incorporated herein by reference to Appendix A to the Company's Proxy Statement for its 2006 Annual Meeting filed on March 29, 2006).
10.1.31	Third Amendment to Credit Agreement dated October 10, 2006 (filed as Exhibit 10.1 to Unit's Form 8-K dated October 10, 2006, which is incorporated herein by reference).
10.1.32	Fourth Amendment to Credit Agreement dated January 25, 2006 (filed as Exhibit 10.1 to Unit's Form 8-K dated January 25, 2006, 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).
10.2.41	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 as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2004).
10.2.45	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).
10.2.46	Unit 2006 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, 2005).
10.2.47	Unit 2007 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 Ryder Scott Company, L.P. (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).

99.3* Consulting Agreement Renewal dated April 12, 2006, between John G. Nikkel and the Registrant (filed as Exhibit 10.1 to Unit's Form 8-K dated April 18, 2006).

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* Indicates a management contract or compensatory plan identified under 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, 2006	$1,612	$ —	$ (12)	$1,600
Year ended December 31, 2005	$1,661	$ —	$ 49	$1,612
Year ended December 31, 2004	$1,223	$ 400	$ (38)	$1,661

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 1, 2007

By: /s/ LARRY D. PINKSTON

LARRY D. PINKSTON
President and 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 1st day of March, 2007.

Name	Title
/s/ JOHN G. NIKKEL **John G. Nikkel**	Chairman of the Board and Director
/s/ LARRY D. PINKSTON **Larry D. Pinkston**	President and Chief Executive Officer, Chief Operating Officer and Director (Principal Executive 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/ GARY CHRISTOPHER **Gary Christopher**	Director
/s/ DON COOK **Don Cook**	Director
/s/ KING P. KIRCHNER **King P. Kirchner**	Director
/s/ WILLIAM B. MORGAN **William B. Morgan**	Director
/s/ ROBERT SULLIVAN, JR. **Robert Sullivan, Jr.**	Director
/s/ JOHN H. WILLIAMS **John H. Williams**	Director

EXHIBIT INDEX

Exhibit No.	Description
10.2.47	Unit 2007 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.
21	Subsidiaries of the Registrant.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Ryder Scott Company, L.P.
31.1	Certification of Chief Executive Officer under Rule 13a-14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a-14(a) of the Exchange Act.
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.