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

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UNIT CORPORATION
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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.

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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.

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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.

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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:

QUARTER	Average Monthly Natural Gas Price per Mcf		Average Monthly Oil Price per Bbl	
	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.

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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.

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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.

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- 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.

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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	Estimated Amount of Commitment Expiration Per Period Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(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.

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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

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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.

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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

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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.

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

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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

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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.

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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.

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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 Comprehen-sive 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

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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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

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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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	2006	2005 (In thousands)	2004
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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

SUPPLEMENTAL INFORMATION

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

	USA	Canada (In thousands)	Total
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

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 (In thousands)	Total
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

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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).

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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).

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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).

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

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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

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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

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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.

EX-10.2.47 2 dex10247.htm UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP AGREEMENT

Exhibit 10.2.47

CONFIDENTIAL

For Private Placement Purposes Only

UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP
7130 South Lewis Avenue, Suite 1000
Tulsa, Oklahoma 74136
(918) 493-7700

A PRIVATE OFFERING
OF
UNITS OF LIMITED PARTNERSHIP INTEREST

THESE SECURITIES HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED, OR UNDER APPLICABLE STATE SECURITIES ACTS IN RELIANCE ON EXEMPTIONS PROVIDED BY SUCH ACTS. THESE SECURITIES MAY NOT BE SOLD OR TRANSFERRED IN THE ABSENCE OF AN EFFECTIVE REGISTRATION UNDER SUCH ACTS OR AN OPINION OF COUNSEL ACCEPTABLE TO THE GENERAL PARTNER THAT SUCH REGISTRATION IS NOT REQUIRED. FURTHER, THE RESALE OF A UNIT MAY RESULT IN SUBSTANTIAL TAX LIABILITY TO THE INVESTOR. SEE "FEDERAL INCOME TAX CONSIDERATIONS." ACCORDINGLY, THESE UNITS SHOULD BE CONSIDERED ONLY FOR LONG-TERM INVESTMENT. SEE "PLAN OF DISTRIBUTION — SUITABILITY OF INVESTORS."

THE INFORMATION CONTAINED IN THIS PRIVATE OFFERING MEMORANDUM IS PROVIDED BY THE GENERAL PARTNER SOLELY FOR THE PERSONS RECEIVING IT FROM THE GENERAL PARTNER AND ANY REPRODUCTION OR DISTRIBUTION OF THIS PRIVATE OFFERING MEMORANDUM, IN WHOLE OR IN PART, OR THE DIVULGENCE OF ANY OF ITS CONTENTS IS PROHIBITED AND MAY CONSTITUTE A VIOLATION OF CERTAIN STATE SECURITIES LAWS. THE OFFEREE, BY ACCEPTING DELIVERY OF THIS PRIVATE OFFERING MEMORANDUM, AGREES TO RETURN IT AND ALL ENCLOSED DOCUMENTS TO THE GENERAL PARTNER IF THE OFFEREE DOES NOT UNDERTAKE TO PURCHASE ANY OF THE UNITS OFFERED HEREBY.

Private Offering Memorandum Date December 27, 2006

900 Preformation
Units of Limited Partnership Interest
in the
UNIT 2007 EMPLOYEE
OIL AND GAS LIMITED PARTNERSHIP

$1,000 Per Unit Plus Possible
Additional Assessments of $100 Per Unit
(Minimum Investment - 2 Units)
Minimum Aggregate Subscriptions Necessary
to Form Partnership - 50 Units

A maximum of 900 (minimum of 50) units of limited partnership interest ("Units") in the UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP, a proposed Oklahoma limited partnership (the "Partnership"), are being offered privately only to certain employees of Unit Corporation ("UNIT") and its subsidiaries and the directors of UNIT at a price of $1,000 per Unit. Subscriptions shall be for not less than 2 Units ($2,000). The Partnership is being formed for the purpose of conducting oil and gas drilling and development operations. Purchasers of the Units will become Limited Partners in the Partnership. Unit Petroleum Company ("UPC" or the "General Partner") will serve as General Partner of the Partnership. UPC's address is 7130 South Lewis Avenue, Suite 1000, Tulsa, Oklahoma 74136, and telephone (918) 493-7700.

THE RIGHTS AND OBLIGATIONS OF THE GENERAL PARTNER AND THE LIMITED PARTNERS ARE GOVERNED BY THE AGREEMENT OF LIMITED PARTNERSHIP (THE "AGREEMENT"), A COPY OF WHICH ACCOMPANIES THIS MEMORANDUM AND IS INCORPORATED HEREIN BY REFERENCE

AN INVESTMENT IN THE UNITS IS SPECULATIVE AND INVOLVES A HIGH DEGREE OF RISK. SEE "RISK FACTORS." CERTAIN SIGNIFICANT RISKS INCLUDE:

- **Drilling to establish productive oil and natural gas properties is inherently speculative.**
- **Participants will rely solely on the management capability and expertise of the General Partner.**
- **Limited Partners must assume the risks of an illiquid investment.**
- **Investment in the Units is suitable only for investors having sufficient financial resources and who desire a long-term investment.**
- **Conflicts of interest exist and additional conflicts of interest may arise between the General Partner and the Limited Partners, and there are no pre-determined procedures for resolving any such conflicts.**
- **Significant tax considerations to be considered by an investor include:**
  - **possible audit of income tax returns of the Partnership and/or the Limited Partners and adjustment to their reported tax liabilities;**
  - **a Limited Partner will not benefit from his or her share of Partnership deductions in excess of his or her share of Partnership income unless he or she has passive income from other activities; and**

- **the amount of any cash distribution which a Limited Partner may receive from the Partnership could be insufficient to pay the tax liability incurred by such Limited Partner with respect to income or gain allocated to such Limited Partner by the Partnership.**

- **There can be no assurance that the Partnership will have adequate funds to provide cash distributions to the Limited Partners. The amount and timing of any such distributions will be within the complete discretion of the General Partner.**

- **Certain provisions in the Agreement modify what would otherwise be the applicable Oklahoma law as to the fiduciary standards for general partners in limited partnerships. Those standards in the Agreement could be less advantageous to the Limited Partners than the corresponding fiduciary standards otherwise applicable under Oklahoma law. The purchase of Units may be deemed as consent to the fiduciary standards set forth in the Agreement.**

EXCEPT AS STATED UNDER "ADDITIONAL INFORMATION," NO PERSON HAS BEEN AUTHORIZED TO GIVE ANY INFORMATION OR TO MAKE ANY REPRESENTATIONS OTHER THAN THOSE CONTAINED IN THIS PRIVATE OFFERING MEMORANDUM IN CONNECTION WITH THIS OFFERING AND SUCH REPRESENTATIONS, IF ANY, MAY NOT BE RELIED ON. THE INFORMATION CONTAINED IN THIS PRIVATE OFFERING MEMORANDUM IS AS OF THE DATE OF THIS MEMORANDUM UNLESS ANOTHER DATE IS SPECIFIED.

PROSPECTIVE INVESTORS ARE NOT TO CONSTRUE THE CONTENTS OF THIS PRIVATE OFFERING MEMORANDUM AS LEGAL, BUSINESS, OR TAX ADVICE. EACH INVESTOR SHOULD CONSULT HIS OR HER OWN ATTORNEY, BUSINESS ADVISOR AND TAX ADVISOR AS TO LEGAL, BUSINESS, TAX AND RELATED MATTERS CONCERNING HIS OR HER INVESTMENT. PROSPECTIVE INVESTORS ARE URGED TO REQUEST ANY ADDITIONAL INFORMATION THEY MAY CONSIDER NECESSARY TO MAKE AN INFORMED INVESTMENT DECISION.

THE SECURITIES OFFERED BY THIS MEMORANDUM HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION, THE OKLAHOMA SECURITIES COMMISSION OR BY THE SECURITIES REGULATORY AUTHORITY OF ANY OTHER STATE, NOR HAS ANY COMMISSION OR AUTHORITY PASSED ON OR ENDORSED THE MERITS OF THIS OFFERING OR THE ACCURACY OR ADEQUACY OF THIS PRIVATE OFFERING MEMORANDUM. ANY REPRESENTATION CONTRARY TO THE FOREGOING IS UNLAWFUL.

THESE UNITS ARE BEING OFFERED SUBJECT TO PRIOR SALE, TO WITHDRAWAL, CANCELLATION OR MODIFICATION OF THE OFFER WITHOUT NOTICE AND TO THE FURTHER CONDITIONS SET FORTH HEREIN.

ADDITIONAL INFORMATION

Each prospective investor, or his or her qualified representative named in writing, has the opportunity (1) to obtain additional information necessary to verify the accuracy of the information supplied herewith or hereafter, and (2) to ask questions and receive answers concerning the terms and conditions of the offering. If you desire to avail yourself of the opportunity, please contact:

Mark E. Schell
Senior Vice President and General Counsel
Unit Petroleum Company
7130 South Lewis Avenue, Suite 1000
Tulsa, Oklahoma 74136
(918) 493-7700

The following documents and instruments are available to qualified offerees on written request:

1. Amended and Restated Certificate of Incorporation and By-Laws of UNIT.
2. Certificate of Incorporation and By-Laws of Unit Petroleum Company.
3. UNIT's Employees' Thrift Plan.
4. Restated Unit Corporation Amended and Restated Stock Option Plan and related prospectuses covering shares of Common Stock issuable on exercise of outstanding options.
5. UNIT's 2002 Non-Employee Directors' Stock Option Plan.
6. The Credit Agreement and the notes payable of UNIT.
7. All periodic reports on Forms 10-K, 10-Q and 8-K and all proxy materials filed by or on behalf of UNIT with the SEC under the Securities Exchange Act of 1934, as amended, during calendar year 2006, the annual report to shareholders and all quarterly reports to shareholders submitted by UNIT to its shareholders during calendar year 2006.
8. Unit's current Registration Statements on Form S-3 and all supplemental prospectuses filed with the SEC under Rule 424.
9. The agreements of limited partnership for the prior oil and gas drilling programs and prior employee programs of UPC, UNIT and Unit Drilling and Exploration Company (**"UDEC"**).
10. All periodic reports filed with the SEC and all reports and information provided to limited partners in all limited partnerships of which UPC, UNIT or UDEC now serves or has served in the past as a general partner.
11. The agreement of limited partnership for the Unit 1986 Energy Income Limited Partnership.

SUMMARY OF CONTENTS

SUMMARY OF PROGRAM

This summary is not a complete description of the terms and consequences of an investment in the Partnership and is qualified in its entirety by the more detailed information appearing throughout this Private Offering Memorandum (this **"Memorandum"**). For definitions of certain terms used in this Memorandum, see "GLOSSARY."

Terms of the Offering

Limited Partnership Interests. Unit 2007 Employee Oil and Gas Limited Partnership, a proposed Oklahoma limited partnership (the **"Partnership"**), offers 900 preformation units of limited partnership interest (**"Units"**) in the Partnership. The offer is made only to certain employees of Unit Corporation (**"UNIT"**) and its subsidiaries and directors of UNIT (see "TERMS OF THE OFFERING — Subscription Rights"). Unless the context otherwise requires, all references in this Memorandum to UNIT shall include all or any of its subsidiaries. Unit Petroleum Company (**"UPC"** or the **"General Partner"**), a wholly owned subsidiary of UNIT, will serve as General Partner of the Partnership.

To invest in the Units, the Limited Partner Subscription Agreement and Suitability Statement (the **"Subscription Agreement"**) (see Attachment I to Exhibit A to this Memorandum) must be signed and forwarded to the offices of the General Partner at its address listed on the cover of this Memorandum. The Subscription Agreement must be received by the General Partner not later than 5:00 P.M. Central Standard Time on January 22, 2007 (extendable by the General Partner for up to 30 days). Subscription Agreements may be delivered to the office of the General Partner. No payment is required on delivery of the Subscription Agreement. Payment for the Units will be made either (i) in four equal Installments, the first Installment being due on March 15, 2007 and the remaining three Installments being due on June 15, September 15, and December 15, 2007, respectively, or (ii) through equal deductions from 2007 salary commencing immediately after formation of the Partnership.

The purchase price of each Unit is $1,000, and the minimum permissible purchase is two Units ($2,000) for each subscriber. Additional Assessments of up to $100 per Unit may be required (see "ADDITIONAL FINANCING — Additional Assessments"). Maximum purchases by employees (other than directors) will be for an amount equal to one-half of their base salaries for calendar year 2006; provided, however, that the General Partner may, at its discretion, accept subscriptions for greater amounts. Each member of the Board of Directors of UNIT may subscribe for up to 300 Units ($300,000). The Partnership must sell at least 50 Units ($50,000) before the Partnership will be formed. No Units will be offered for sale after the Effective Date (see "GLOSSARY") except on compliance with the provisions of Article XIII of the Agreement. The General Partner may, at its option, purchase Units as a Limited Partner, including any amount that may be necessary to meet the minimum number of Units required for formation of the Partnership. The Partnership will terminate on December 31, 2037, unless it is terminated earlier under the provisions of the Agreement or by operation of law. See "TERMS OF THE OFFERING — Limited Partnership Interests"; "TERMS OF THE OFFERING — Subscription Rights"; and "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Termination."

The offering will be made privately by the officers and directors of UPC or UNIT, except that in states which require participation by a registered broker-dealer in the offer and sale of securities, the Units will be offered through such broker-dealer as may be selected by the General Partner. Any participating broker-dealer may be reimbursed for actual out-of-pocket expenses. Such reimbursements will be borne by the General Partner.

Subscription Rights. Only salaried employees of UNIT or any of its subsidiaries whose annual base salaries for 2007 has been set at $36,000 or more and directors of UNIT are eligible to subscribe for Units. Employees may not purchase Units for an amount in excess of one-half of their base salaries for calendar year 2007; provided, however, that the General Partner may, at its discretion, accept a subscription for a greater amount. Directors' subscriptions may not be for more than 300 Units ($300,000). Only employees and directors who are U.S. citizens are eligible to participate in the offering. In addition, employees and directors must be able to bear the economic risks of an investment in the Partnership and must have sufficient investment experience and expertise to evaluate the risks and merits of such an investment. See "TERMS OF THE OFFERING — Subscription Rights."

Right of Presentment. After December 31, 2008, the Limited Partners will have the right to present their Units to the General Partner for purchase. The General Partner will not be obligated to purchase more than 20% of the then outstanding Units in any one calendar year. The purchase price to be paid for the Units will be determined by a specific valuation formula. See "TERMS OF THE OFFERING — Right of Presentment" for a description of the valuation formula and a discussion of the manner in which the right of presentment may be exercised by the Limited Partners.

Risk Factors

An investment in the Partnership has many risks. The "RISK FACTORS" section of this Memorandum contains a detailed discussion of the most important risks, organized into Investment Risks (the risks related to the Partnership's investment in oil and gas properties and drilling activities, to an investment in the Partnership and to the provisions of the Agreement); Tax Risks (the risks arising from the tax laws as they apply to the Partnership and its investment in oil and gas properties and drilling activities); and Operational Risks (the risks involved in conducting oil and gas operations). The following are certain of the risks which are more fully described under "RISK FACTORS". Each prospective investor should review the "RISK FACTORS" section carefully before deciding to subscribe for Units.

Investment Risks:

- Future oil and natural gas prices are unpredictable. Partnership's distributions, if any, to the Limited Partners will be adversely affected by declines in oil and natural gas prices.

- Due to substantial increases in the prices for crude oil and natural gas production recently experienced, the demand for oil and gas leaseholds, services of drilling rigs, drilling supplies, and producing oil and gas properties has increased substantially. This increased demand has resulted in substantial increases in the costs of these various items. These increased costs increase the risks of achieving profitable operations, particularly if oil and natural gas prices decline or, in some cases, don't increase materially.

- The General Partner is authorized under the Agreement to cause, in its sole discretion, the sale or transfer of the Partnership's assets to, or the merger or consolidation of the Partnership with, another partnership, corporation or other business entity. Such action could have a material impact on the nature of the investment of all Limited Partners.

- Except for certain transfers to the General Partner and other restricted transfers, the Agreement prohibits a Limited Partner from transferring Units. Thus, except for the limited right of the Limited Partners after December 31, 2008 to present their Units to the General Partner for purchase, Limited Partners will not be able to liquidate their investments.

- The Partnership could be formed with as little as $50,000 in Capital Contributions (excluding the Capital Contributions of the General Partner). As the total amount of Capital Contributions to the Partnership will determine the number and diversification of Partnership Properties, the ability of the Partnership to pursue its investment objectives may be restricted in the event that the Partnership receives only the minimum amount of Capital Contributions.

- The drilling and completion operations to be undertaken by the Partnership for the development of oil and natural gas reserves involve the possibility of a total loss of an investment in the Partnership.

- The General Partner will have the exclusive management and control of all aspects of the business of the Partnership. The Limited Partners will have no opportunity to participate in the management and control of any aspect of the Partnership's activities. Accordingly, the Limited Partners will be entirely dependent on the management skills and expertise of the General Partner.

- Conflicts of interest exist and additional conflicts of interest may arise between the General Partner and the Limited Partners, and there are no pre-determined procedures for resolving any conflicts. Accordingly the General Partner could cause the Partnership to take actions to the benefit of the General Partner but not to the benefit of the Limited Partners.

- Certain provisions in the Agreement modify what would otherwise be the applicable Oklahoma law as to the fiduciary standards for a general partner in a limited partnership. The fiduciary standards in the Agreement could be less advantageous to the Limited Partners and more advantageous to the General Partner than corresponding fiduciary standards otherwise applicable under Oklahoma law. The purchase of Units may be deemed as consent to the fiduciary standards set forth in the Agreement.

- There can be no assurances that the Partnership will have adequate funds to provide cash distributions to the Limited Partners. The amount and timing of any such distributions will be within the complete discretion of the General Partner.

- The amount of any cash distributions which Limited Partners may receive from the Partnership could be insufficient to pay the tax liability incurred by such Limited Partners with respect to income or gain allocated to such Limited Partners by the Partnership.

Tax Risks:

- Tax laws and regulations applicable to partnership investments may change at any time and these changes may be applied retroactively.

- Certain allocations of income, gain, loss and deduction between the Partners may be challenged by the Internal Revenue Service (the **"Service"**). A successful challenge would likely result in a Limited Partner having to report additional taxable income or being denied a deduction.

- It is anticipated that a Limited Partner will be allocated deductions in excess of his or share of Partnership income for the first year(s) of the Partnership. Unless a Limited Partner has substantial current taxable income from trade or business activities in which the Limited Partner does not materially participate, his or her use of deductions allocated from the Partnership may be limited.

- Federal income tax payable by a Limited Partner by reason of his or her allocated share of Partnership income for any year may exceed the Partnership distributions to that Limited Partner for the year.

Operational Risks:

- The search for oil and gas is highly speculative and the drilling activities conducted by the Partnership may result in wells that may be dry or wells that do not produce sufficient oil and gas to produce a profit or result in a return of the Limited Partners' investment.

- Certain hazards are encountered in drilling wells some of which could lead to substantial liabilities to third parties or governmental entities. Also, governmental regulations or new laws relating to environmental matters could increase Partnership costs, delay or prevent drilling a well, require the Partnership to cease operations in certain areas or expose the Partnership to significant liabilities for violations of laws and regulations.

Additional Financing

Additional Assessments. After the Aggregate Subscription has been fully expended or committed and the General Partner's Minimum Capital Contribution has been fully expended, the General Partner may make one or more calls for Additional Assessments if additional funds are required to pay the Limited Partners' share of Drilling Costs, Special Production and Marketing Costs or Leasehold Acquisition Costs. The maximum amount of total Additional Assessments which may be called for by the General Partner is $100 per Unit. See "ADDITIONAL FINANCING — Additional Assessments."

Partnership Borrowings. After the General Partner's Minimum Capital Contribution has been expended, the General Partner may cause the Partnership to borrow funds required to pay Drilling Costs, Special Production and Marketing Costs or Leasehold Acquisition Costs of Productive properties. The General Partner may also, but is not required to, advance funds to the Partnership to pay those costs. See "ADDITIONAL FINANCING — Partnership Borrowings."

Proposed Activities

General. The Partnership is being formed for the purposes of conducting oil and gas drilling and development operations and acquiring producing oil and gas properties. The Partnership will, with certain limited exceptions, participate on a proportionate basis with UPC in each producing oil and gas lease acquired and in each oil and gas well participated in by UPC for its own account during the period from January 1, 2007, if the Partnership is formed before that date or from the date of the formation of the Partnership if formed after January 1, 2007, until December 31, 2007, and will, with certain limited exceptions, serve as a co-general partner with UPC in any drilling or income programs which may be formed by the General Partner in 2007. See "PROPOSED ACTIVITIES."

Partnership Objectives. The Partnership is being formed to provide eligible employees and directors the opportunity to participate in the oil and gas exploration and producing property acquisition activities of UPC during 2007. UNIT hopes that participation in the Partnership will provide the participants with greater proprietary interests in UPC's operations and the potential for realizing a more direct benefit in the event these operations prove to be profitable. The Partnership has been structured to achieve the objective of providing the Limited Partners with essentially the same economic returns that UPC realizes from the wells drilled or acquired during 2007.

Application of Proceeds

The offering proceeds will be used to pay the Leasehold Acquisition Costs incurred by the Partnership to acquire those producing oil and gas leases in which the Partnership participates and the Leasehold Acquisition Costs, exploration, drilling and development costs incurred by the Partnership under the drilling activities in which the Partnership participates. The General Partner estimates (based on historical operating experience) that those costs will be expended as shown below based on the assumption of a maximum number of subscriptions in the first column and a minimum number of subscriptions in the second column:

	$900,000 Program	$50,000 Program
Leasehold Acquisition Costs of Properties to Be Drilled	$ 45,000	$ 2,500
Drilling Costs of Exploratory Wells(1)	45,000	2,500
Drilling Costs of Development Wells(1)	630,000	35,000
Leasehold Acquisition Costs of Productive Properties	180,000	10,000
Reimbursement of General Partner's Overhead Costs(2)	—	—
Total	$900,000	$50,000

(1) See "GLOSSARY."

(2) The Agreement provides that the General Partner will be reimbursed by the Partnership for that part of its general and administrative overhead expense attributable to the conduct of Partnership business and affairs but that any reimbursement will be made only out of Partnership Revenue. See "COMPENSATION."

Participation in Costs and Revenues

Partnership costs, expenses and revenues will be allocated among the Partners in the following percentages:

	General Partner	Limited Partners
COSTS AND EXPENSES		
Organizational and offering costs of the Partnership and any drilling or income programs in which the Partnership participates as a co-general partner	100%	0%
All other Partnership costs and expenses		
Prior to time Limited Partner Capital Contributions are entirely expended	1%	99%
After expenditure of Limited Partner Capital Contributions and until expenditure of General Partner's Minimum Capital Contribution	100%	0%
After expenditure of General Partner's Minimum Capital Contribution	General Partner's Percentage[1]	Limited Partners' Percentage[1]
REVENUES	General Partner's Percentage[1]	Limited Partners' Percentage[1]

(1) See "GLOSSARY."

Compensation

The General Partner will not receive any management fees in connection with the operation of the Partnership. The Partnership will reimburse the General Partner for that portion of its general and administrative overhead expense attributable to its conduct of Partnership business and affairs. See "COMPENSATION."

Federal Income Tax Considerations; Opinion of Counsel

The General Partner has received an opinion from its tax counsel, Conner & Winters, LLP ("Conner & Winters"), concerning all material federal income tax issues applicable to an investment in the Partnership. To be fully understood, the complete discussion of these matters set forth in the full tax opinion in Exhibit B should be read by each prospective investor. Based on current laws, regulations, interpretations, and court decisions, Conner & Winters has rendered its opinion that (i) the material federal income tax benefits in the aggregate from an investment in the Partnership will be realized; (ii) the Partnership will be treated as a partnership for federal income tax purposes and not as a corporation, an association taxable as a corporation or a publicly traded partnership; (iii) to the extent the Partnership's wells are timely drilled and its drilling costs are timely paid, then subject to the limitations on deductions discussed in such opinion, the Partners will be entitled to their pro rata shares of the Partnership's intangible drilling and development costs ("IDC") paid in 2007; (iv) for most Limited Partners, the Partnership's operations will be considered a passive activity within the meaning of Section 469 of the Internal Revenue Code of 1986, as amended (the "Code"), and losses generated therefrom will be limited by the passive activity provisions of the Code; (v) to the extent provided in the opinion, the Partners' distributive shares of Partnership tax items will be determined and allocated substantially in accordance with the terms of the Partnership Agreement; and (vi) the Partnership will not be required to register with the Service as a tax shelter.

Due to the lack of authority regarding, or the essentially factual nature of certain issues, Conner & Winters expresses no opinion on the following: (i) the impact of an investment in the Partnership on an investor's alternative minimum tax liability; (ii) whether, under Code Section 183, the losses of the Partnership will be treated as derived from "activities not engaged in for profit," and therefore nondeductible from other gross income (due to the inherently factual nature of a Partner's interest and motive in investing in the Partnership); (iii) whether any of the Partnership's properties will be considered "proven" for purposes of depletion deductions; (iv) whether any interest incurred by a Partner with respect to any borrowings incurred to purchase Units will be deductible or subject to limitations on deductibility; and (v) whether the Partnership will be treated as the tax owner of Partnership Properties acquired by the General Partner as nominee for the Partnership.

The opinion of Conner & Winters was not intended or written to be used, and cannot be used, for the purpose of avoiding penalties that may be imposed by the Service. The opinion of Conner & Winters was written to support the promotion or marketing of Units in the Partnership. Prospective investors should seek advice based on their particular circumstances from an independent tax advisor.

THIS MEMORANDUM CONTAINS AN EXPLANATION OF THE MORE SIGNIFICANT TERMS AND PROVISIONS OF THE AGREEMENT OF LIMITED PARTNERSHIP WHICH IS ATTACHED AS EXHIBIT A. THE SUMMARY OF THE AGREEMENT CONTAINED IN THIS MEMORANDUM IS QUALIFIED IN ITS ENTIRETY BY SUCH REFERENCE AND ACCORDINGLY THE AGREEMENT SHOULD BE CAREFULLY REVIEWED AND CONSIDERED.

RISK FACTORS

Prospective purchasers of Units should carefully study the information contained in this Memorandum and should make their own evaluations of the probability for the discovery of oil and natural gas through exploration.

INVESTMENT RISKS

Financial Risks of Drilling Operations

The Partnership will participate with the General Partner (including, with certain limited exceptions, other drilling programs sponsored by it) and, in many cases, other parties (**"joint interest parties"**) in connection with drilling operations conducted on properties in which the Partnership has an interest. It is not anticipated that most, if any, of these drilling operations will be conducted under turnkey drilling contracts and, thus, all of the parties participating in the drilling operations on a particular property, including the Partnership, will be fully liable for their proportionate share of all the costs of those operations even if the actual costs are much more than the original cost estimates. Further, if any joint interest party fails to pay its share of the costs, the other joint interest parties may be required to pay the deficiency until, if ever, it can be collected from the defaulting party. As a result of forced pooling or similar proceedings (see "COMPETITION, MARKETS AND REGULATION"), the Partnership may acquire a larger ownership interest in certain Partnership Properties than originally anticipated and, thus, be required to bear a greater share of the costs of operations. Because of the foregoing, the Partnership could become liable for amounts significantly more than the amounts originally anticipated to be spent in connection with its operations and would have only limited means for providing the additional needed funds (see "ADDITIONAL FINANCING"). Also, a company that operates a Partnership Well does not or cannot pay the costs and expenses of drilling or operating the well, the Partnership's interest in that well may become subject to liens and claims of creditors who supplied services or materials in connection with such operations even though the Partnership may have previously paid its share of such costs and expenses to the operator. If the operator is unable or unwilling to pay the amount due, the Partnership might have to pay its share of the amounts owing to such creditors in order to preserve its interest in the well which would mean that it would, in effect, be paying for certain of such costs and expenses twice.

Dependence on General Partner

The Limited Partners will acquire interests in the Partnership, not in the General Partner or UNIT. Limited Partners will not participate in either increases or decreases in the General Partner's or UNIT's net worth or the value of either's common stock. Nevertheless, because the General Partner is primarily responsible for the proper conduct of the Partnership's business and affairs and is obligated to provide certain funds that will be required in connection with the Partnership's operations, a significant reversal of the General Partners or UNIT's finances could have an adverse effect on the Partnership and the Limited Partners' interests in the Partnership.

Under the Agreement, UPC is designated as the General Partner of the Partnership and is given the exclusive authority to manage and operate the Partnership's business. See "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Power and Authority". Accordingly, Limited Partners must rely solely on the General Partner to make all decisions on behalf of the Partnership, since the Limited Partners will have no role in the management of the business of the Partnership.

The Partnership's success will depend, in part, on the management provided by the General Partner, the ability of the General Partner to select and acquire oil and gas properties on which Partnership Wells capable of producing oil and natural gas in commercial quantities may be drilled, to fund the acquisition of revenue producing properties, and to market oil and natural gas produced from Partnership Wells.

Conflicts of Interest

Certain of UNIT's subsidiaries have engaged in oil and gas exploration and development and in the acquisition of producing properties for their own account and as the sponsors of drilling and income programs formed with third party investors. It is anticipated that those subsidiaries will continue to engage in those activities. However, with certain exceptions, it is likely that the Partnership will participate as a working interest owner in all producing oil and gas leases acquired and in all oil and gas wells participated in by the General Partner for its own account during the period from January 1, 2007 (if the Partnership is formed before that date) or from the date of the formation of the Partnership, if after January 1, 2007, through December 31, 2007 and, with certain limited exceptions, will be a co-general partner of any drilling or income programs, or both, formed by the General Partner or UNIT in 2007. The General Partner will determine which prospects will be acquired or drilled. With respect to prospects to be drilled, certain of the wells which are drilled for the separate account of the Partnership and the General Partner may be drilled on prospects on which initial drilling operations were conducted by the General Partner before the formation of the Partnership. Further, certain Partnership Wells will be drilled on prospects on which the General Partner and possibly future employee programs may conduct additional drilling operations in years after 2007. Except with respect to its participation as a co-general partner of any drilling or income program sponsored by the General Partner or UNIT, the Partnership will have an interest only in those wells started in 2007 and will have no rights in production from wells started in years other than 2007. Likewise, if additional interests are acquired in wells participated in by the Partnership after 2007, the Partnership will generally not be entitled to share in the acquisition of that additional interests. See "CONFLICTS OF INTEREST — Acquisition of Properties and Drilling Operations."

The Partnership may enter into contracts for the drilling of some or all of the Partnership Wells with affiliates of the General Partner. Likewise the Partnership may sell or market some or all of its natural gas production to an affiliate of the General Partner. These contracts may not necessarily be negotiated on an arm's—length basis. The General Partner is subject to a conflict of interest in selecting an affiliate of the General Partner to drill the Partnership Wells and/or market the natural gas therefrom. The compensation under these contracts will be determined at the time each contract is made. The costs to be paid or the sale price to be received under each contract will be competitive with the costs charged or the prices paid by unaffiliated parties in the same general geographic region. The General Partner will make the determination of what are competitive rates or prices. No provision has been made for an independent review of the fairness and reasonableness of such compensation. See "CONFLICTS OF INTERESTS — Transactions with the General Partner or Affiliates."

Prohibition on Transferability; Lack of Liquidity

Except for certain transfers (i) to the General Partner, (ii) to or for the benefit of the transferor Limited Partner or members of his or her immediate family sharing the same residence, and (iii) by reason of death or operation of law, a Limited Partner may not transfer or assign Units. The General Partner has agreed, that it will, if requested at any time after December 31, 2008, buy Units for prices determined either by an independent petroleum engineering firm or the General Partner using the formula described under "TERMS OF THE OFFERING — Right of Presentment." The General Partner's obligation to purchase Units is limited and does not assure the liquidity of a Limited Partner's investment, and the price received may be less than if the Limited Partner continued to hold his or her Units. In addition, similar commitments by the General Partner have been made (and may hereafter be made) to investors in other oil and gas drilling, income and employee programs. There can be no assurance that the General Partner will have the financial resources to honor its repurchase commitments. See "TERMS OF THE OFFERING — Right of Presentment."

Delay of Cash Distributions

For income tax purposes, a Limited Partner must report his or her distributive (allocated) share of the income, gains, losses and deductions of the Partnership whether or not cash distributions are made. No cash distributions are expected to be made earlier than the first quarter of 2008. In addition, to the extent that the Partnership uses its revenues to repay borrowings or to finance its activities (see "ADDITIONAL FINANCING"), the funds available for cash distributions by the Partnership will be reduced or may be unavailable. It is possible that the amount of tax payable by a Limited Partner on his or her distributive share of the income of the Partnership will exceed his or her cash distributions from the Partnership. See "FEDERAL INCOME TAX CONSIDERATIONS."

If and the date any distributions commence and their subsequent timing or amount cannot be accurately predicted. The decision as to whether or not the Partnership will make a cash distribution at any particular time will be made solely by the General Partner.

Limitations on Voting and Other Rights of Limited Partners

The Agreement, as permitted under the Oklahoma Revised Uniform Limited Partnership Act (the **"Act"**), eliminates or limits the rights of the Limited Partners to take certain actions, such as:

- withdrawing from the Partnership,
- transferring Units without restrictions, or
- consenting to or voting on certain matters such as:
  - (i) admitting a new General Partner,
  - (ii) admitting Substituted Limited Partners, and
  - (iii) dissolving the Partnership.

Furthermore, the Agreement imposes restrictions on the exercise of voting rights granted to Limited Partners. See "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Voting Rights." Without the provisions to the contrary which are contained in the Agreement, the Act provides that certain actions can be taken only with the consent of all Limited Partners. Those provisions of the Agreement which provide for or require the vote of the Limited Partners, generally permit the approval of a proposal by the vote of Limited Partners holding a majority of the outstanding Units. See "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Voting Rights." Thus, Limited Partners who do not agree with or do not wish to be subject to the proposed action may nevertheless become subject to the action if the required majority approval is obtained. Notwithstanding the rights granted to Limited Partners under the Agreement and the Act, the General Partner retains substantial discretion as to the operation of the Partnership.

Rollup or Consolidation of Partnership

Under the terms of the Agreement, at any time two years or more after the Partnership has completed substantially all of its property acquisition, drilling and development operations, the General Partner is authorized to cause the Partnership to transfer its assets to, or to merge or consolidate with, another partnership or a corporation or other entity for the purpose of combining the oil and gas properties and other assets of the Partnership with those of other partnerships formed for investment or participation by the employees, directors and/or consultants of UNIT or any of its subsidiaries. Such transfer or combination may be effected without the vote, approval or consent of the Limited Partners. In such event, the Limited Partners will receive interests in the transferee or resulting entity which will mean that they will most likely participate in the results of a larger number of properties but will have proportionately smaller allocable interests therein. Any such transaction is required to be effected in a manner which UNIT and the General Partner believe is fair and equitable to the Limited Partners but there can be no assurance that such transaction will in fact be in the best interests of the Limited Partners. Limited Partners have no dissenters' or appraisal rights under the terms of the Agreement or the Act. Such a transaction would result in the termination and dissolution of the Partnership. While there can be no assurance that the Partnership will participate in such a transaction, the General Partner currently anticipates that the Partnership will, at the appropriate time, be involved in such a transaction. See "TERMS OF OFFERING," and "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT."

Partnership Borrowings

The General Partner has the authority to cause the Partnership to borrow funds to pay certain costs of the Partnership. While the use of financing to preserve the Partnership's equity in oil and gas properties will be intended to increase the Partnership's profits, such financing could have the effect of increasing the Partnership's losses if the Partnership is unsuccessful. In addition, the Partnership may have to mortgage its oil and gas properties and other assets in order to obtain additional financing. If the Partnership defaults on such indebtedness, the lender may foreclose and the Partnership could lose its investment in such oil and gas properties and other assets. See "ADDITIONAL FINANCING — Partnership Borrowings."

Limited Liability

Under the Act a Limited Partner's liability for the obligations of the Partnership is limited to such Limited Partner's Capital Contribution and such Limited Partner's share of Partnership assets. In addition, if a Limited Partner receives a return of any part of his or her Capital Contribution, such Limited Partner is generally liable to the Partnership for a period of one year thereafter (or six years in the event such return is in violation of the Agreement) for the amount of the returned contribution. A Limited Partner will not otherwise be liable for the obligations of the Partnership unless, in addition to the exercise of his or her rights and powers as a Limited Partner, such Limited Partner participates in the control of the business of the Partnership.

The Agreement provides that by a vote of a majority in interest, the Limited Partners may effect certain changes in the Partnership such as termination and dissolution of the Partnership and amendment of the Agreement. The exercise of any of these and certain other rights is conditioned on receipt of an opinion by Conner & Winters for the Limited Partners or an order or judgment of a court of competent jurisdiction to the effect that the exercise of such rights will not result in the loss of the limited liability of the Limited Partners or cause the Partnership to be classified as an association taxable as a corporation (see "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Amendments" and "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Termination"). As a result of certain judicial opinions it is not clear that these rights will ever be available to the Limited Partners. Nevertheless, in spite of the receipt of any such opinion or judicial order, it is still possible that the exercise of any such rights by the Limited Partners may result in the loss of the Limited Partners' limited liability. The Partnership will be governed by the Act. The Act expressly permits limited partners to vote on certain specified partnership matters without being deemed to be participating in the control of the Partnership's business and, thus, should result in greater certainty and more easily obtainable opinions of Conner & Winters regarding the exercise of most of the Limited Partners' rights.

If the Partnership is dissolved and its business is not to be continued, the Partnership will be wound up. In connection with the winding up of the Partnership, all of its properties may be sold and the proceeds thereof credited to the accounts of the Partners. Properties not sold will, on termination of the Partnership, be distributed to the Partners. The distribution of Partnership Properties to the Limited Partners would result in their having unlimited liability with respect to such properties. See "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Limited Liability."

Partnership Acting as Co-General Partner

It is anticipated that the Partnership will serve as a co-general partner in any drilling or income programs formed by the General Partner or UNIT during 2007. See "PROPOSED ACTIVITIES." Accordingly, the Partnership generally will be liable for the obligation and recourse liabilities of any such drilling or income program formed. While a Limited Partner's liability for such claims will be limited to such Limited Partners Capital Contribution and share of Partnership assets, such claims if satisfied from the Partnership's assets could adversely affect the operations of the Partnership.

Past-Due Installments; Acceleration; Additional Assessments

Installments and Additional Assessments (see "ADDITIONAL FINANCING") are legally binding obligations and past-due amounts will bear interest at the rate set forth in the Agreement; provided, however, that if the General Partner determines that the total Aggregate Subscription is not required to fund the Partnership's business and operations, then the General Partner may, at its sole option, elect to release the Limited Partners from their obligation to pay one or more Installments and amend any relevant Partnership documents accordingly. It is anticipated that the total Aggregate Subscription will be required to fund the Partnership's business and operations. In the event an Installment is not paid when due and the General Partner has not released the Limited Partners from their obligation to pay such Installment, then the General Partner may, at its sole option, purchase all Units of the director or employee who fails to pay such Installment, at a price equal to the amount of the prior Installments paid by such person. The General Partner may also bring legal proceedings to collect any unpaid Installments not waived by it or Additional Assessments. In addition, as indicated under "TERMS OF THE OFFERING — Payment for Units; Delinquent Installment," if an employee's employment with or position as a director of the General Partner, UNIT or any affiliate thereof is terminated other than by reason of Normal Retirement (see "GLOSSARY"), death or disability prior to the time the full amount of the subscription price for his or her Units has been paid, all unpaid Installments not waived by the General Partner as described above will become due and payable on such termination.

Partnership Funds

Except for Capital Contributions, Partnership funds are expected to be commingled with funds of the General Partner or UNIT. Thus, Partnership funds could become subject to the claims of creditors of the General Partner or UNIT. The General Partner believes that its assets and net worth are such that the risk of loss to the Partnership by virtue of such fact is minimal but there can be no assurance that the Partnership will not suffer losses of its funds to creditors of the General Partner or UNIT.

Compliance with Federal and State Securities Laws

This offering has not been registered under the Securities Act of 1933, as amended, in reliance on exemptions from the registration provisions of that act. Further, these interests are being sold pursuant to exemptions from registration in the various states in which they are being offered and may be subject to additional restrictions in such jurisdictions on transfer. There is no assurance that the offering presently qualifies or will continue to qualify under such exemptions due to, among other things, the adequacy of disclosure and the manner of distribution of the offering, the existence of similar offerings conducted by the General Partner or UNIT or its affiliates in the past or in the future, a failure or delay in providing notices or other required filings, the conduct of other oil and gas activities by the General Partner or UNIT and its affiliates or the change of any securities laws or regulations.

If and to the extent suits for rescission are brought and successfully concluded for failure to register this offering or other offerings under the Securities Act of 1933, as amended, or state securities acts, or for acts or omissions constituting certain prohibited practices under any of said acts, both the capital and assets of the General Partner and the Partnership could be adversely affected, thus jeopardizing the ability of the Partnership to operate successfully. Further, the time and capital of the General Partner could be expended in defending an action by investors or by state or federal authorities even where the Partnership and the General Partner are ultimately exonerated.

Title to Properties

The Partnership Agreement empowers the General Partner, UNIT or any of their affiliates, to hold title to the Partnership Properties for the benefit of the Partnership. As such it is possible that the Partnership Properties could be subject to the claims of creditors of the General Partner. The General Partner is of the opinion that the likelihood of the occurrence of such claims is remote. However, the Partnership Property could be subject to claims and litigation in the event that the General Partner failed to pay its debts or became subject to the claims of creditors.

Use of Partnership Funds to Exculpate and Indemnify the General Partner

The Agreement contains certain provisions which are intended to limit the liability of the General Partner and its affiliates for certain acts or omissions within the scope of the authority conferred on them by the Agreement. In addition, under the Agreement, the General Partner will be indemnified by the Partnership against losses, judgments, liabilities, expenses and amounts paid in settlement sustained by it in connection with the Partnership so long as the losses, judgments, liabilities, expenses or amounts were not the result of gross negligence or willful misconduct on the part of the General Partner. See "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Exculpation and Indemnification of the General Partner."

The Partnership Agreement May Limit the Fiduciary Obligation of the General Partner to the Partnership and the Limited Partners

The Agreement contains certain provisions which modify what would otherwise be the applicable Oklahoma law relating to the fiduciary standards of the General Partner to the Limited Partners. The fiduciary standards in the Agreement could be less advantageous to the Limited Partners and more advantageous to the General Partner than the corresponding fiduciary standards otherwise applicable under Oklahoma law (although there are very few legal precedents clarifying exactly what fiduciary standards would otherwise be applicable under Oklahoma law). The purchase of Units may be deemed as consent to the fiduciary standards set forth in the Agreement. See "FIDUCIARY RESPONSIBILITY." As a result of these provisions in the Agreement, the Limited Partners may find it more difficult to hold the General Partner responsible for acting in the best interest of the Partnership and the Limited Partners than if the fiduciary standards of the otherwise applicable Oklahoma law governed the situation.

TAX STATUS AND TAX RISKS

It is possible that the tax treatment currently available with respect to oil and gas exploration and production will be modified or eliminated on a retroactive or prospective basis by legislative, judicial, or administrative actions. The limited tax benefits associated with oil and gas exploration do not eliminate the inherent economic risks. See "Federal Income Tax Considerations."

Partnership Classification

Conner & Winters has rendered its opinion that the Partnership will be classified for federal income tax purposes as a partnership and not as a corporation, an association taxable as a corporation or a "publicly traded partnership." Such opinion is not binding on the Service or the courts. If the Partnership were classified as a corporation, association taxable as a corporation or publicly traded partnership, any income, gain, loss, deduction, or credit of the Partnership would remain at the entity level, and not flow through to the Partners, the income of the Partnership would be subject to corporate tax rates at the entity level and distributions to the Partners could be considered dividend distributions. See "Federal Income Tax Considerations—General Tax Effects of Partnership Structure."

Limited Partner Interests

It is anticipated that in the first year(s) of the Partnership Limited Partners will be allocated deductions in excess of their allocations of income. An investment as a Limited Partner may not be advisable for a person who does not anticipate having substantial current taxable income from passive trade or business activities (not counting dividend or interest income). Most Limited Partners will be subject to the "passive activity loss" rules. A Limited Partner subject to the passive activity loss rules will be unable to use passive losses generated by the Partnership until and unless he or she has realized "passive income".

Tax Liabilities in Excess of Cash Distributions

A Partner must include in his or her own income tax return his or her share of the items of the Partnership's income, gain, profit, loss, and deductions whether or not cash proceeds are actually distributed to the Partner to pay any tax resulting from the Partnership's income or gain. For example, income from the Partnership's sale of oil and gas production will be taxable to Partners as ordinary income subject to depletion and other deductions whether or not the proceeds from such sale are actually distributed (for example, where Partnership income is used to repay Partnership indebtedness).

Items Not Covered by the Tax Opinion

Due to the lack of authority regarding, or the essentially factual nature of certain issues, Conner & Winters has expressed no opinion as to the following: (i) the impact of an investment in the Partnership on an investor's alternative minimum tax liability; (ii) whether any of the Partnership's properties will be considered "proven" for purposes of depletion deductions; and (iii) whether the Partnership will be treated as the tax owner of Partnership Properties acquired by the General Partner as nominee for the Partnership.

The determination of the proper treatment as to the above-referenced issues is dependent on facts not currently available. Therefore, Conner & Winters is unable to render an opinion at this time with respect to such issues. Also, the unknown facts with respect to the various issues referred to above will vary from Partner to Partner and will result in different tax consequences and burdens for individual Partners.

Tax Opinion Not Binding on Service

Prospective investors should recognize that an opinion of legal counsel merely represents such counsel's best legal judgment under existing statutes, judicial decisions, and administrative regulations and interpretations. There can be no assurance that deductions claimed by the Partnership in reliance on the opinion of Conner & Winters will not be challenged successfully by the Service.

The opinion of Conner & Winters was not intended or written to be used, and cannot be used, for the purpose of avoiding penalties that may be imposed by the Service. The opinion of Conner & Winters was written to support the promotion or marketing of Units in the Partnership. Prospective investors should seek advice based on their particular circumstances from an independent tax advisor.

OPERATIONAL RISKS

Risks Inherent in Oil and Gas Operations

The Partnership will be participating with the General Partner in acquiring producing oil and gas leases and in the drilling of those oil and gas wells commenced by the General Partner from the later of January 1, 2007 or the time the Partnership is formed through December 31, 2007 and, with certain limited exceptions, serving as a co-general partner of any oil and gas drilling or income programs, or both, formed by the General Partner or UNIT during 2007.

All drilling to establish productive oil and natural gas properties is inherently speculative. The techniques presently available to identify the existence and location of pools of oil and natural gas are indirect, and, therefore, a considerable amount of personal judgment is involved in the selection of any prospect for drilling. The economics of oil and natural gas drilling and production are affected or may be affected in the future by a number of factors which are beyond the control of the General Partner, including (i) the general demand in the economy for energy fuels, (ii) the worldwide supply of oil and natural gas, (iii) the price of, as well as governmental policies with respect to, oil and liquefied natural gas imports, (iv) potential competition from competing alternative fuels, (v) governmental regulation of prices for oil and natural gas production, gathering and transportation, (vi) state regulations affecting allowable rates of production, well spacing and other factors such as, but not limited to, regulation of gathering, and (vii) availability of drilling rigs, casing and other necessary goods and services. See "COMPETITION, MARKETS AND REGULATION." The revenues, if any, generated from Partnership operations will be highly dependent on the future prices and demand for oil and natural gas. The factors enumerated above affect, and will continue to affect, oil and natural gas prices. Recently, prices for oil and natural gas have fluctuated over a wide range.

Operating and Environmental Hazards

Operating hazards such as fires, explosions, blowouts, unusual formations, formations with abnormal pressures and other unforeseen conditions are sometimes encountered in drilling wells. On occasion, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could reduce the funds available for exploration and development or result in loss of Partnership Properties. The Partnership will attempt to maintain customary insurance coverage, but the Partnership may be subject to liability for pollution and other damages or may lose substantial portions of its properties due to hazards against which it cannot insure or against which it may elect not to insure due to unreasonably high or prohibitive premium costs or for other reasons. The activities of the Partnership may expose it to drilling limitations and potential liability for pollution or other damages under laws and regulations relating to environmental matters (see “Government Regulation and Environmental Risks” below).

Competition

The oil and gas industry is highly competitive. The Partnership will be involved in intense competition for the acquisition of quality undeveloped leases and producing oil and gas properties. There can be no assurance that a sufficient number of suitable oil and gas properties will be available for acquisition or development by the Partnership. The Partnership will be competing with numerous major and independent companies which possess financial resources and staffs larger than those available to it. The Partnership, therefore, may be unable in certain instances to acquire desirable leases or supplies or may encounter delays in commencing or completing Partnership operations.

Markets for Oil and Natural Gas Production

Historically, oil and gas prices have been extremely volatile, with significant increases and significant price drops being experienced from time to time. In the future, various factors beyond the control of the Partnership will have a significant effect on oil and gas prices. Such factors include, among other things, the domestic and foreign supply of oil and gas, the price of foreign imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity and changes in existing and proposed federal regulation and price controls.

Although future levels of production by international oil producing companies or the degree to which oil prices will be affected thereby and other world events cannot be predicted, it is possible that prices for oil produced in the future will be higher or lower than those currently available. Although future levels of production by international oil producing countries or the degree to which oil prices will be affected thereby and other world events cannot be predicted, it is possible that prices for oil produced in the future will be higher or lower than those currently available. There can be no assurance that the oil that the Partnership produces can be marketed on favorable price and other contractual terms. See “COMPETITION, MARKETS AND REGULATION — Marketing of Production.”

The natural gas market is also unsettled due to a number of factors. In the past, production from natural gas wells in some geographic areas of the United States was curtailed for considerable periods of time due to a lack of market demand. Over the past several years demand for natural gas has increased greatly limiting the number of wells being shut in for lack of demand. It is possible, however, that Partnership Wells may in the future be shut-in or that natural gas will be sold on terms less favorable than might otherwise be obtained should demand for gas lessen in the future. Competition for available markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. In recent years, significant court decisions and regulatory changes have affected the natural gas markets. As a result of such court decisions, regulatory changes and unsettled market conditions, natural gas regulations may be modified in the future and may be subject to further judicial review or invalidation. The combination of these factors, among others, makes it particularly difficult to estimate accurately future prices of natural gas, and any assumptions concerning future prices may prove incorrect. Natural gas surpluses could result in the Partnership’s inability to market natural gas profitably, causing Partnership Wells to curtail production and/or receive lower prices for its natural gas, situations which would adversely affect the Partnership’s ability to make cash distributions to its participants. See “COMPETITION, MARKETS AND REGULATION.”

In the event that the Partnership discovers or acquires natural gas reserves, there may be delays in commencing or continuing production due to the need for gathering and pipeline facilities, contract negotiation with the available market, pipeline capacities, seasonal takes by the gas purchaser or a surplus of available gas reserves in a particular area.

Government Regulation and Environmental Risks

The oil and gas business is subject to pervasive government regulation under which, among other things, rates of production from producing properties may be fixed and the prices for gas produced from such producing properties may be impacted. It is possible that these regulations pertaining to rates of production could become more pervasive and stringent in the future. The activities of the Partnership may expose it to potential liability under laws and regulations relating to environmental matters which could adversely affect the Partnership. Compliance with these laws and regulations may increase Partnership costs, delay or prevent the drilling of wells, delay or prevent the acquisition of otherwise desirable producing oil and gas properties, require the Partnership to cease operations in certain areas, and cause delays in the production of oil and gas. See "COMPETITION, MARKETING AND REGULATION."

Leasehold Defects

In certain instances, the Partnership may not be able to obtain a title opinion or report with respect to a producing property that is acquired. Consequently, the Partnership's title to any such property may be uncertain. Furthermore, even if certain technical defects do appear in title opinions or reports with respect to a particular property, the General Partner, in its sole discretion, may determine that it is in the best interest of the Partnership to acquire such property without taking any curative action.

TERMS OF THE OFFERING

General

- 900 Maximum Units; 50 Minimum Units
- $1,000 Units; Minimum subscription: $2,000
- Minimum Partnership: $50,000 in subscriptions
- Maximum Partnership: $900,000 in subscriptions

Limited Partnership Interests

The Partnership hereby offers to certain employees (described under "Subscription Rights" below) and directors of UNIT and its subsidiaries an aggregate of 800 Units. The purchase price of each Unit is $1,000, and the minimum permissible purchase by any eligible subscriber is two Units ($2,000). See "Subscription Rights" below for the maximum number of Units that may be acquired by subscribers.

The Partnership will be formed as an Oklahoma limited partnership on the closing of the offering of Units made by this Memorandum. The General Partner will be Unit Petroleum Company (the **"General Partner"**, or **"UPC"**), an Oklahoma corporation. Partnership operations will be conducted from the General Partner's offices, the address of which is 7130 South Lewis Avenue, Suite 1000, Tulsa, Oklahoma 74136, telephone (918) 493-7700.

The offering of Units will be closed on January 22, 2007 unless extended by the General Partner for up to 30 days, and all Units subscribed will be issued on the Effective Date. The offering may be withdrawn by the General Partner at any time prior to such date if it believes it to be in the best interests of the eligible employees and Directors or the General Partner not to proceed with the offering.

If at least 50 Units ($50,000) are not subscribed prior to the termination of the offering, the Partnership will not commence business. The General Partner may, on its own accord, purchase Units and, in such capacity, will enjoy the same rights and obligations as other Limited Partners, except the General Partner will have unlimited liability. The General Partner may, in its discretion, purchase Units sufficient to reach the minimum Aggregate Subscription ($50,000). Because the General Partner or its affiliates might benefit from the successful completion of this offering (see "PARTICIPATION IN COSTS, AND REVENUES" and "COMPENSATION"), investors should not expect that sales of the minimum Aggregate Subscription indicate that such sales have been made to investors that have no financial or other interest in the offering or that have otherwise exercised independent investment discretion. Further, the sale of the minimum Aggregate Subscription is not designed as a protection to investors to indicate that their interest is shared by other unaffiliated investors and no investor should place any reliance on the sale of the minimum Aggregate Subscription as an indication of the merits of this offering. Units acquired by the General Partner will be for investment purposes only without a present intent for resale and there is no limit on the number of Units that may be acquired by it.

Subscription Rights

Units are offered only to persons who are salaried employees of UNIT or its subsidiaries at the date of formation of the Partnership and whose annual base salaries for 2007 (excluding bonuses) has been set at $36,000 or more and to directors of UNIT. Only employees and directors who are U.S. citizens are eligible to participate in the offering. In addition, employees and directors must be able to bear the economic risks of an investment in the Partnership and must have sufficient investment experience and expertise to evaluate the risks and merits of such an investment. See "PLAN OF DISTRIBUTION — Suitability of Investors."

Eligible employees and directors are restricted as to the number of Units they may purchase in the offering. The maximum number of Units which can be acquired by any employee is that number of whole Units which can be purchased with an amount which does not exceed one-half of the employee's base salary for 2007; provided, however, that the General Partner may, at its discretion, accept a subscription for a greater amount. Each director of UNIT may subscribe for a maximum of 300 Units (maximum investment of $300,000). At December 15, 2006 there were approximately 597 people eligible to purchase Units.

Eligible employees and directors may acquire Units through a corporation or other entity in which all of the beneficial interests are owned by them or permitted assignees (see "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Transferability of Interests"); provided that such employees or Directors will be jointly and severally liable with such entity for payment of the Capital Subscription.

If all eligible employees and directors subscribed for the maximum number of Units, the Units would be oversubscribed. In that event, Units would be allocated among the respective subscribers in the proportion that each subscription amount bears to total subscriptions obtained.

No employee is obligated to purchase Units in order to remain in the employ of UNIT, and the purchase of Units by any employee will not obligate UNIT to continue the employment of such employee. Units may be subscribed for by the spouse or a trust for the minor children of eligible employees and directors.

Payment for Units; Delinquent Installment

The Capital Subscriptions of the Limited Partners will be payable either (i) in four equal Installments, the first of such Installments being due on March 15, 2007 and the remaining three of such Installments being due on June 15, September 15, and December 15, 2007, respectively, or (ii) by employees so electing in the space provided on the Subscription Agreement, through equal deductions from 2007 salary paid to the employee by the General Partner, UNIT or its subsidiaries commencing immediately after formation of the Partnership. If an employee or director who has subscribed for Units (either directly or through a corporation or other entity) ceases to be employed by or serve as a director of the General Partner, UNIT or any of its subsidiaries for any reason other than death, disability or Normal Retirement prior to the time the full amount of all Installments not waived by the General Partner as described below are due, then the due date for any such unpaid Installments shall be accelerated so that the full amount of his or her unpaid Capital Subscription will be due and payable on the effective date of such termination.

Each Installment will be a legally binding obligation of the Limited Partner and any past due amounts will bear interest at an annual rate equal to two percentage points in excess of the prime rate of interest of Bank of Oklahoma, N.A., Tulsa, Oklahoma; provided, however, that if the General Partner determines that the total Aggregate Subscription is not required to fund the Partnership's business and operations, then the General Partner may, at its sole option, elect to release the Limited Partners from their obligation to pay one or more Installments. If the General Partner elects to waive the payment of an Installment, it will notify all Limited Partners promptly in writing of its decision and will, to the extent required, amend the certificate of limited partnership and any other relevant Partnership documents accordingly. It is currently anticipated that the total Aggregate Subscription will be required, however, to fund the Partnership's business and operations.

In the event a Limited Partner fails to pay any Installment when due and the General Partner has not released the Limited Partners from their obligation to pay such Installment, then the General Partner, at its sole option and discretion, may elect to purchase the Units of such defaulting Limited Partner at a price equal to the total amount of the Capital Contributions actually paid into the Partnership by such defaulting Limited Partner, less the amount of any Partnership distributions that may have been received by him or her. Such option may be exercised by the General Partner by written notice to the Limited Partner at any time after the date that the unpaid Installment was due and will be deemed exercised when the amount of the purchase price is first tendered to the defaulting Limited Partner. The General Partner may, in its discretion, accept payments of delinquent Installments not waived by it but will not be required to do so.

In the event that the General Partner elects to purchase the Units of a defaulting Limited Partner, it must pay into the Partnership the amount of the delinquent Installment (excluding any interest that may have accrued thereon) and pay each additional Installment, if any, payable with respect to such Units as it becomes due. By virtue of such purchase, the General Partner will be allocated all Partnership Revenues, be charged with all Partnership costs and expenses attributable to such Units and will enjoy the same rights and obligations as other Limited Partners, except the General Partner will have unlimited liability.

Right of Presentment

After December 31, 2008, and annually thereafter, Limited Partners will have the right to present their Units to the General Partner for purchase. The General Partner will not be obligated to purchase more than 20% of the then outstanding Units in any one calendar year. The purchase price to be paid for the Units of any Limited Partner presenting them for purchase will be based on the net asset value of the Partnership which shall be equal to:

(1) The value of the proved reserves attributable to the Partnership Properties, determined as set forth below; plus

(2) The estimated salvage value of tangible equipment installed on Partnership Wells less the costs of plugging and abandoning the wells, both discounted at the rate utilized to determine the value of the Partnership's reserves as set forth below; plus

(3) The lower of cost or fair market value of all Partnership Properties to which proved reserves have not been attributed but which have not been condemned, as determined by an independent petroleum engineering firm or the General Partner, as the case may be; plus

(4) Cash on hand; plus

(5) Prepaid expenses and accounts receivable (less a reasonable reserve for doubtful accounts); plus

(6) The estimated market value of all other Partnership assets not included in (1) through (5) above, determined by the General Partner; MINUS

(7) An amount equal to all debts, obligations and other liabilities of the Partnership.

The price to be paid for each Limited Partner's interest of the net asset value will be his or her proportionate share of such net asset value less 75% of the amount of any distributions received by him or her which are attributable to the sales of the Partnership production since the date as of which the Partnership's proved reserves are estimated.

The value of the proved reserves attributable to Partnership Properties will be determined as follows:

(i) First, the future net revenues from the production and sale of the proved reserves will be estimated as of the end of the calendar year in which presentment is made based on an independent engineering firm's report and its determinations of the prices to be used as well as the escalations, if any, of such prices and cost or, if no report was made, as determined by the General Partner;

(ii) Next, the future net revenues from the production and sale of proved reserves as determined above will be discounted at an annual rate which is one percentage point higher than the prime rate of interest being charged by the Bank of Oklahoma, N.A., Tulsa, Oklahoma, or any successor bank, as of the date such reserves are estimated; and

(iii) Finally, the total discounted value of the future net revenues from the production and sale of proved reserves will be reduced by an additional 25% to take into account the risks and uncertainties associated with the production and sale of the reserves and other unforeseen uncertainties.

A Limited Partner who elects to have his or her Units purchased by the General Partner should be aware that estimates of future net recoverable reserves of oil and gas and estimates of future net revenues to be received therefrom are based on a great many factors, some of which, particularly future prices of production, are usually variable and uncertain and are always determined by predictions of future events. Accordingly, it is common for the actual production and revenues received to vary from earlier estimates. Estimates made in the first few years of production from a property will be based on relatively little production history and will not be as reliable as later estimates based on longer production history. As a result of all the foregoing, reserve estimates and estimates of future net revenues from production may vary from year to year.

This right of presentment may be exercised by written notice from a Limited Partner to the General Partner. The sale will be effective as of the close of business on the last day of the calendar year in which such notice is given or, at the General Partner's election, at 7:00 A.M. on the following day. Within 120 days after the end of the calendar year, the General Partner will furnish each Limited Partner who gave such notice during the calendar year a statement showing the cash purchase price which would be paid for the Limited Partner's interest as of December 31 of the preceding year, which statement will include a summary of estimated reserves and future net revenues and sufficient material to reveal how the purchase price was determined. The Limited Partner must, within 30 days after receipt of such statement, reaffirm his or her election to sell to the General Partner.

As noted above, the General Partner will not be obligated to purchase in any one calendar year more than 20% of the Units in the Partnership then outstanding. Moreover, the General Partner will not be obligated to purchase any Units pursuant to such right if such purchase, when added to the total of all other sales, exchanges, transfers or assignments of Units within the preceding 12 months, would result in the Partnership being considered to have terminated within the meaning of Section 708 of the Code or would cause the Partnership to lose its status as a partnership or be treated as a publicly traded partnership for federal income tax purposes. If more than the number of Units which may be purchased are tendered in any one year, the Limited Partners from whom the Units are to be purchased will be determined by lot. Any Units presented but not purchased with respect to one year will have priority for such purchase the following year.

The General Partner does not intend to establish a cash reserve to fund its obligation to purchase Units, but will use funds provided by its operations or borrowed funds (if available), using its assets (including such Units purchased or to be purchased from Limited Partners) as collateral to fund such obligations. However, there is no assurance that the General Partner will have sufficient financial resources to discharge its obligations.

Rollup or Consolidation of Partnership

The Agreement provides that two years or more after the Partnership has completed substantially all of its property acquisition, drilling and development operations, the General Partner may, without the vote, consent or approval of the Limited Partners, cause all or substantially all of the oil and gas properties and other assets of the Partnership to be sold, assigned or transferred to, or the Partnership merged or consolidated with, another partnership or a corporation, trust or other entity for the purpose of combining the assets of two or more of the oil and gas partnerships formed for investment or participation by employees, directors and/or consultants of UNIT or any of its subsidiaries; provided, however, that the valuation of the oil and gas properties and other assets of all such participating partnerships for purposes of such transfer or combination shall be made on a consistent basis and in a manner which the General Partner and UNIT believe is fair and equitable to the Limited Partners. As a consequence of any such transfer or combination, the Partnership shall be dissolved and terminated and the Limited Partners shall receive partnership interests, stock or other equity interests in the transferee or resulting entity. Any such action will cause the Limited Partners' attributable interest in the Partnership Properties to be diluted but it will also provide them with attributable interests in the properties and other assets of the other partnerships participating in the consolidation. It also may reduce somewhat the amount of their attributable shares of the direct and indirect costs of administering the Partnership. See "RISK FACTORS — Investment Risks-Roll-Up or Consolidation of Partnership."

ADDITIONAL FINANCING

The General Partner will use its best efforts, consistent with Partnership objectives, to acquire Productive properties and complete the Partnership's drilling and development operations before the Aggregate Subscription has been fully expended or committed. However, funds in addition to the Aggregate Subscription may be required to pay costs and expenses which are chargeable to the Limited Partners. In those instances described below, the General Partner may call for Additional Assessments or may apply Partnership Revenue allocable to the Limited Partners in payment and satisfaction of such costs or the General Partner may, but shall not be required to, fund the deficiency with Partnership borrowings to be repaid with Partnership Revenue.

Additional Assessments

When the Aggregate Subscription has been fully expended or committed, the General Partner may make one or more calls for any portion or all of the maximum Additional Assessments of $100 per Unit. However, no Additional Assessments may be required before the General Partner's Minimum Capital Contribution has been fully expended. Such assessments may be used to pay the Limited Partners' share of the Drilling Costs, Special Production and Marketing Costs or Leasehold Acquisition Costs of Productive properties which are chargeable to the Limited Partners. The amount of the Additional Assessment so called shall be due and payable on or before such date as the General Partner may set in such call, which in no event will be earlier than thirty (30) days after the date of mailing of the call. The notice of the call for Additional Assessments will specify the amount of the assessment being required, the intended use of such funds, the date on which the contributions are payable and describe the consequences of nonpayment. Although the Limited Partners who do not respond will participate in production, if any, obtained from operations conducted with the proceeds from the aggregate Additional Assessments paid into the Partnership, the amount of the unpaid Additional Assessment shall bear interest at the annual rate equal to two (2) percentage points in excess of the prime rate of interest of Bank of Oklahoma, N.A., Tulsa, Oklahoma, or successor bank, as announced and in effect from time to time, until paid. The Partnership will have a lien on the defaulting Limited Partner's interest in the Partnership and the General Partner may retain Partnership Revenue otherwise available for distribution to the defaulting Limited Partner until an amount equal to the unpaid Additional Assessment and interest is received. Furthermore, the General Partner may satisfy such lien by proceeding with legal action to enforce the lien and the defaulting Limited Partner shall pay all expenses of collection, including interest, court costs and a reasonable attorney's fee.

Prior Programs

In the prior employee programs conducted by UNIT or the General Partner in each of the years 1984 through 2006, Additional Assessments could be called for as provided herein. At September 30, 2006, there had been no calls for Additional Assessments in such programs. There can be no assurance, however, that Additional Assessments will not be required to pay Partnership costs.

Partnership Borrowings

At any time after the General Partner's Minimum Capital Contribution has been fully expended, the General Partner may cause the Partnership to borrow funds for the purpose of paying Drilling Costs, Special Production and Marketing Costs or Leasehold Acquisition Costs of Productive properties, which borrowings may be secured by interests in the Partnership Properties and will be repaid, including interest accruing thereon, out of Partnership Revenue. The General Partner may, but is not required to, advance funds to the Partnership for the same purposes for which Partnership borrowings are authorized. With respect to any such advances, the General Partner will receive interest in an amount equal to the lesser of the interest which would be charged to the Partnership by unrelated banks on comparable loans for the same purpose or the General Partner's interest cost with respect to such loan, where it borrows the same. No financing charges will be levied by the General Partner in connection with any such loan. If Partnership borrowings secured by interests in the Partnership Wells and repayable out of Partnership Revenue cannot be arranged on a basis which, in the opinion of the General Partner, is fair and reasonable, and the entire sum required to pay such costs is not available from Partnership Revenue, the General Partner may dispose of some or all of the Partnership Properties on which such operations were to be conducted by sale, farm-out or abandonment.

If the Partnership requires funds to conduct Partnership operations during the period between any of the Installments due from the Limited Partners, then, notwithstanding the foregoing, the General Partner shall advance funds to the Partnership in an amount equal to the funds then required to conduct such operations but in no event more than the total amount of the Aggregate Subscription remaining unpaid. With respect to any such advances, the General Partner shall receive no interest thereon and no financing charges will be levied by the General Partner in connection therewith. The General Partner shall be repaid out of the Installments thereafter paid into the capital of the Partnership when due.

The Partnership may attempt to finance any expenses in excess of the Partners' Capital Subscriptions by the foregoing means and any other means which the General Partner deems in the best interests of the Partnership, but the Partnership's inability to meet such costs could result in the deferral of drilling operations or in the inability to participate in future drilling or in non-consent penalties pursuant to which co-owners of particular working interests recover several times the amount which would have been funded by the Partnership in accordance with its ownership interest before the Partnership would participate in revenues.

The use of Partnership Revenue allocable to the Limited Partners to pay Partnership costs and expenses and to repay any Partnership borrowings will mean that such revenue will not be available for distribution to the Limited Partners. Nonetheless, the Limited Partners may incur income tax liability by virtue of that revenue and, thus, may not receive distributions from the Partnership in amounts necessary to pay such income tax. However, the use of such revenue to pay Partnership costs and expenses may generate additional deductions for the Limited Partners.

PLAN OF DISTRIBUTION

Units will be offered privately only to select persons who can demonstrate to the General Partner that they have both the economic means and investment expertise to qualify as suitable investors. The Units will be offered and sold by the officers and directors of UPC or UNIT.

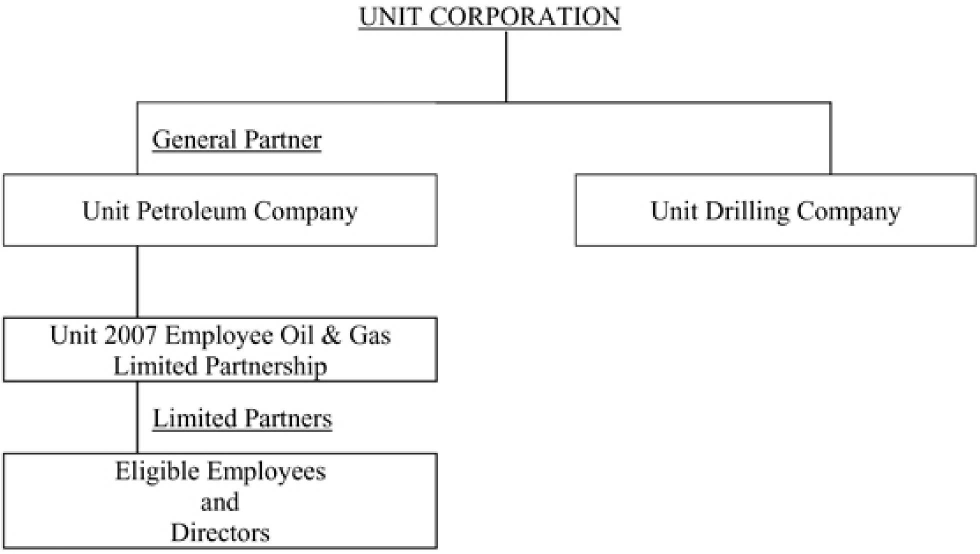
Suitability of Investors

Subscriptions should be made only by appropriate persons who can reasonably benefit from an investment in the Partnership. In this regard, a subscription will generally be accepted only from a person who can represent that such person has (or in the case of a husband and wife, acting as joint tenants, tenants in common or tenants in the entirety, that they have) a net worth, including home, furnishings and automobiles, of at least five times the amount of his or her Capital Subscription, and estimates that such person will have during the current year adjusted gross income in an amount which will enable him or her to bear the economic risks of his or her investment in the Partnership. Such person must also demonstrate that he or she has sufficient investment experience and expertise to evaluate the risks and merits of an investment in the Partnership.

Participation in the Partnership is intended only for those persons willing to assume the risk of a speculative, illiquid, long-term investment. Entitlement to and maintenance of the exemptions from registration provided by Sections 3(b) and/or 4(2) of the Securities Act of 1933, as amended, require the imposition of certain limitations on the persons to whom offers may be made, and from whom subscriptions may be accepted. Therefore, this offering is limited to persons who, by virtue of investment acumen or financial resources, satisfy the General Partner that they meet suitability standards consistent with the maintenance and preservation of the exemptions provided by Sections 3(b) and/or 4(2) and by the applicable rules and regulations of the Securities and Exchange Commission, as well as those contained herein and in the Subscription Agreement. Persons offering interests shall sufficiently inquire of a prospective investor to be reasonably assured that such investor meets such acceptable standards. Suitability standards may also be imposed by the regulatory authorities of the various states in which interests may be offered.

**RELATIONSHIP OF THE PARTNERSHIP,
THE GENERAL PARTNER AND AFFILIATES**

The following diagram depicts the primary relationships among the Partnership, the General Partner and certain of its affiliates.



PROPOSED ACTIVITIES

General

The Partnership will, with certain limited exceptions, participate in all of UNIT's or UPC's oil and gas activities commenced during 2007. The Partnership will acquire 1% of essentially all of UNIT's interest in such activities. The activities will include (i) participating as a joint working interest owner with UNIT or UPC in any producing leases acquired and in any wells commenced by UNIT or UPC other than as a general partner in a drilling or income program during 2006 and (ii) serving as a co-general partner in any drilling or income programs, or both, formed by the General Partner or UNIT during 2007.

Acquisition of Properties and Drilling Operations. The Partnership will participate, to the extent of 1% of UPC or UNIT's final interest in each well, as a fractional working interest holder in any producing leases acquired and in any drilling operations conducted by UPC or UNIT for its own account which are acquired or commenced, respectively, from January 1, 2007, or the time of the formation of the Partnership if subsequent to January 1, 2007, until December 31, 2007, except for wells, if any:

(i) drilled outside the 48 contiguous United States;

(ii) drilled as part of secondary or tertiary recovery operations which were in existence prior to formation of the Partnership;

(iii) drilled by third parties under farm-out or similar arrangements with UNIT or the General Partner or whereby UNIT or the General Partner may be entitled to an overriding royalty, reversionary or other similar interest in the production from such wells but is not obligated to pay any of the Drilling Costs thereof;

(iv) acquired by UNIT or the General Partner through the acquisition by UNIT or the General Partner of, or merger of UNIT or the General Partner with, other companies (this exception may, at the discretion of Unit or the General Partner, be waived.); or

(v) with respect to which the General Partner does not believe that the potential economic return therefrom justifies the costs of participation by the Partnership.

Instances referred to in (v) could occur when UNIT or one of its subsidiaries agrees to participate in the ownership of a prospect for its own account in order to obtain the contract to drill the well thereon. There may be situations where the potential economic return of the well alone would not be sufficient to warrant participation by UNIT but when considered in light of the revenues expected to be realized as a result of the drilling contract, such participation is desirable from UNIT's standpoint. However, in such a situation, the Partnership would not be entitled to any of the revenues generated by the drilling contract so its participation in the well would not be desirable.

For these purposes, the drilling of a well will be deemed to have commenced on the "spud date," i.e., the date that the drilling rig is set up and actual drilling operations are commenced. Any clearing or other site preparation operations will not be considered part of the drilling operations for these purposes.

Participation in Drilling or Income Programs. Except for certain limited exceptions it is anticipated that the Partnership will participate with UPC or UNIT as a co-general partner of any drilling or income programs, or both, formed by UPC or UNIT and its affiliates during 2007. The Partnership will be charged with 1% of the total costs and expenses charged to the general partners and allocated 1% of the revenues allocable to the general partners in any such program and UPC or UNIT will be charged with the remaining 99% of the general partners' share of costs and expenses and allocated the remaining 99% of the general partners' share of program revenues.

UNIT or its affiliates formed drilling programs for outside investors from 1979 through 1984. In 1987, the Unit 1986 Energy Income Limited Partnership (the **"1986 Energy Program"**) was formed primarily to acquire interests in producing oil and gas properties. See "PRIOR ACTIVITIES." All of the programs were formed as limited partnerships and interests in all of the programs other than the Unit 1979 Oil and Gas Program and the 1986 Energy Program were offered in registered public offerings. The 1979 Program and 1986 Energy Program were offered privately to a limited number of sophisticated investors.

No drilling or income programs for third party investors were formed in 2006. Although it does not currently contemplate doing so, UNIT may form such drilling or income programs during 2007. If such a program is formed, there would be only one or two such programs and they probably would be privately offered. The precise revenue and cost sharing format of any such programs has not been determined.

The cost and revenue sharing provisions of virtually all drilling programs offered to third parties generally require the limited partners or investors to bear a somewhat higher percentage of the program's drilling and development costs than the percentage of program revenues to which they are entitled. Likewise, the general partners will normally receive a higher percentage of revenues than the percentage of drilling and development costs which they are required to pay. The difference in these percentages is often referred to as the general partners' "promote." Any drilling program which UNIT or UPC may form in 2007 for outside investors would likely have some amount of "promote" for the general partner(s).

Any income program may use the same or a similar format as that used for the 1986 Partnership. In the 1986 Partnership, virtually all partnership costs and expenses other than property acquisition costs are allocated to the partners in the same percentages that partnership revenue is being shared at the time such expenses are incurred, with property acquisition costs and certain other expenses being charged 85% to the accounts of the limited partners and 15% to the accounts of the general partners. Partnership revenue in the 1986 Partnership is allocated 85% to the limited partners' accounts and 15% to the general partners' accounts until program payout (as defined in the agreement of limited partnership for the 1986 Partnership). After program payout, the percentages of partnership revenue allocable to the respective accounts of the partners depend on the length of the period during which program payout occurs and range from 60% to the limited partners' accounts and 40% to the general partners' accounts to 85% to the limited partners' accounts and 15% to the general partners' accounts.

As co-general partners of any drilling or income programs that may be formed by UNIT and/or UPC during 2007 and participated in by the Partnership, UNIT and/or UPC and the Partnership will share the costs, expenses and revenues allocable to the general partners on a proportionate basis, 99% for the account of UNIT and/or UPC and 1% for the account of the Partnership. The Partnership will not receive any portion of any management fees payable to the general partners nor any fees or payments for supervisory services which UNIT or UPC may render to such programs as operator of program wells or other fees and payments which UNIT or UPC may be entitled to receive from such programs for services rendered to them or goods, materials, equipment or other property sold to them.

Extent and Nature of Operations. Although the General Partner maintains a general inventory of prospects, it cannot predict with certainty on which of those prospects wells will be started during 2007 nor can it predict what producing properties, if any, will be acquired by it during 2007. Further, since the General Partner anticipates that the Partnership will acquire a small interest (either directly or through any drilling or income programs of which it or UNIT serves as a general partner) in approximately 260 wells (however, the exact number of wells may vary greatly depending on the actual activity undertaken), it would be impractical to describe in any detail all of the properties in which the Partnership can be expected to acquire some interest.

The Partnership's drilling and development operations are expected to include both Exploratory Wells and comparatively lower-risk Development Wells. Exploratory Wells include both the high-risk "wildcat" wells which are located in areas substantially removed from existing production and "controlled" Exploratory Wells which are located in areas where production has been established and where objective horizons have produced from similar geological features in the vicinity. Based on UNIT's historical profile of its drilling operations, it is presently anticipated that the portion of the Aggregate Subscription expended for Partnership drilling operations (see "APPLICATION OF PROCEEDS") will be spent approximately 7% on Exploratory Wells and 93% on Development Wells. However, these percentages may vary significantly.

Certain of the Partnership's Development Wells may be drilled on prospects on which initial drilling operations were conducted by the General Partner or UNIT prior to the formation of the Partnership. Further, certain of the Partnership Wells will be drilled on prospects on which the General Partner, UNIT or possibly future employee programs may conduct additional drilling operations in years subsequent to 2007. In either instance, the Partnership will have an interest only in those wells begun in 2007 and will have no rights in production from wells commenced in years other than 2007 even though such other wells may be located on prospects or spacing units on which Partnership Wells have been drilled. Furthermore, it is possible that in years subsequent to 2007, UNIT, UPC or possibly future employee programs will acquire additional interests in wells participated in by the Partnership. In such event the Partnership will generally not be entitled to share in the acquisition of such additional interests. With respect to the acquisition of producing properties, UNIT will endeavor to diversify its investments by acquiring properties located in differing geographic locations and by balancing its investments between properties having high rates of production in early years and properties with more consistent production over a longer term. See "CONFLICTS OF INTERESTS — Acquisition of Properties and Drilling Operations."

Partnership Objectives

The Partnership is being formed to provide eligible employees and directors the opportunity to participate in the oil and gas exploration and producing property acquisition activities of UNIT during 2007. UNIT hopes that participation in the Partnership will provide the participants with greater proprietary interests in its operations and the potential for realizing a more direct benefit in the event these operations prove to be profitable. The Partnership has been structured to achieve the objective of providing the Limited Partners with essentially the same economic returns that UNIT realizes from the wells drilled or acquired during 2007.

Areas of Interest

The Agreement authorizes the Partnership to engage in oil and gas exploration, drilling and development operations and to acquire producing oil and gas properties anywhere in the United States, but the areas presently under consideration are located in the states of Oklahoma, Texas, Louisiana, Kansas, Arkansas, Colorado, Montana, North Dakota, New Mexico, Mississippi and Wyoming. It is possible that the Partnership may drill in inland waterways, riverbeds, bayous or marshes but no drilling in the open seas will be attempted. Plans to conduct drilling and development operations or to acquire producing properties in certain of these states may be abandoned if attractive prospects cannot be obtained on satisfactory terms or if the Partnership is not fully subscribed.

Transfer of Properties

In the case of wells drilled or producing properties acquired by the Partnership and UPC or UNIT for their own accounts and not through another drilling or income program, the Partnership will acquire from UPC or UNIT a portion of the fractional undivided working interest in the properties or portions thereof comprising the spacing unit on which a proposed Partnership Well is to be drilled or on which a producing Partnership Well is located, and UPC or UNIT will retain for its own account all or a portion of the remainder of such working interest. Such working interests will be sold to the Partnership for an amount equal to the Leasehold Acquisition Costs attributable to the interest being acquired. Neither UNIT nor its affiliates will retain any overrides or other burdens on the working interests conveyed to the Partnership, and the respective working interests of UPC or UNIT and the Partnership in a property will bear their proportionate shares of costs and revenues.

The Partnership’s direct interest in a property will only encompass the area included within the spacing unit on which a Partnership Well is to be drilled or on which a producing Partnership Well is located, and, in the case of a Partnership Well to be drilled, it will acquire that interest only when the drilling of the well is ready to commence. If the size of a spacing unit is ever reduced, or any subsequent well in which the Partnership has no interest is drilled thereon, the Partnership will have no interest in any additional wells drilled on properties which were part of the original spacing unit unless such additional wells are commenced during 2007. If additional interests in Partnership Wells are acquired in years subsequent to 2007 the Partnership will generally not be entitled to participate or share in the acquisition of such additional interests. In addition, if the Partnership Well drilled on a spacing unit is dry or abandoned, the Partnership will not have an interest in any subsequent or additional well drilled on the spacing unit unless it is commenced during 2007. The Partnership will never own any significant amounts of undeveloped properties or have an occasion to sell or farm out any undeveloped Partnership Properties.

Transfers of properties to any drilling or income programs of which the Partnership serves as a general partner will be governed by the provisions of the agreement of limited partnership in effect with respect thereto. If any such program is to be offered publicly, those provisions will have to be consistent with the provisions contained in the Guidelines for the Registration of Oil and Gas Programs adopted by the North American Securities Administrators Association, Inc.

Record Title to Partnership Properties

Record title to the Partnership Properties will be held by the General Partner. However, the General Partner will hold the Partnership Properties as a nominee for the Partnership under a form of nominee agreement to be entered into between the General Partner and the Partnership. Under the form of nominee agreement, the General Partner will disclaim any beneficial interest in the Partnership Properties held as nominee for the Partnership.

Marketing of Reserves

The General Partner has the authority to market the oil and gas production of the Partnership. In this connection, it may execute on behalf of the Partnership division orders, contracts for the marketing or sale of oil, gas or other hydrocarbons or other marketing agreements. Sales of the oil and gas production of the Partnership will be to independent third parties or to the General Partner or its affiliates (see “CONFLICTS OF INTEREST”).

Conduct of Operations

The General Partner will have full, exclusive and complete discretion and control over the management, business and affairs of the Partnership and will make all decisions affecting the Partnership Properties. To the extent that Partnership funds are reasonably available, the General Partner will cause the Partnership to (1) test and investigate the Partnership Properties by appropriate geological and geophysical means, (2) conduct drilling and development operations on such Partnership Properties as it deems appropriate in view of such testing and investigation, (3) attempt completion of wells so drilled if in its opinion conditions warrant the attempt and (4) properly equip and complete productive Partnership Wells. The General Partner will also cause the Partnership's productive wells to be operated in accordance with sound and economical oil and gas recovery practices.

The General Partner will operate certain drilling and productive wells on behalf of the Partnership in accordance with the terms of the Agreement (see "COMPENSATION"). In those cases, execution of separate operating agreements will not be necessary unless third party owners are involved, e.g., fractional undivided interest Partnership Properties and Partnership Properties that are pooled or unitized with other properties owned by third parties. In such cases, and in all cases where Partnership Properties are operated by third parties, the General Partner will, where appropriate, make or cause to be made and enter into operating agreements, pooling agreements, unitization agreements, etc., in the form in general use in the area where the affected property is located. The General Partner is also authorized to execute production sales contracts on behalf of the Partnership.

APPLICATION OF PROCEEDS

The Aggregate Subscription will be used to pay costs and expenses incurred in the operations of the Partnership which are chargeable to the Limited Partners. The organizational costs of the Partnership and the offering costs of the Units will be paid by the General Partner.

If all 900 Units offered hereby are sold, the proceeds to the Partnership would be $900,000. If the minimum 50 Units are sold, the proceeds to the Partnership would be $50,000. The General Partner estimates that the gross proceeds will be expended as follows:

	$900,000 Program		$50,000 Program	
	Percent	Amount	Percent	Amount
Leasehold Acquisition Costs of Properties to Be Drilled	5%	$ 45,000	5%	$ 2,500
Drilling Costs of Exploratory Wells	5%	45,000	5%	2,500
Drilling Costs of Development Wells	70%	630,000	70%	35,000
Leasehold Acquisition Costs of Productive Properties	20%	180,000	20%	10,000
Total	100%	$900,000	100%	$50,000

The foregoing allocation between Drilling Costs and Leasehold Acquisition Costs is solely an estimate and the actual percentages may vary materially from this estimate. Funds otherwise available for drilling Exploratory Wells will be reduced to the extent that such funds are used in conducting development operations in which the Partnership participates.

Until Capital Contributions are invested in the Partnership's operations, they will be temporarily deposited, with or without interest, in one or more bank accounts of the Partnership or invested in short-term United States government securities, money market funds, bank certificates of deposit or commercial paper rated as "A1" or "P1" as the General Partner deems advisable. Partnership funds other than Capital Contributions may be commingled with the funds of the General Partner or UNIT.

PARTICIPATION IN COSTS AND REVENUES

All costs of organizing the Partnership and offering Units therein will be paid by the General Partner. All costs incurred in the offering and syndication of any drilling or income program formed by UPC or UNIT and its affiliates during 2007 in which the Partnership participates as a co-general partner will also be paid by the General Partner. All other Partnership costs and expenses will be charged 99% to the Limited Partners and 1% to the General Partner until such time as the Aggregate Subscription has been fully expended. Thereafter and until the General Partner's Minimum Capital Contribution has been fully expended, all of such costs and expenses will be charged to the General Partner. After the General Partner's Minimum Capital Contribution has been fully expended, such costs and expenses will be charged to the respective accounts of the General Partner and the Limited Partners on the basis of their respective Percentages (see "GLOSSARY").

All Partnership Revenues will be allocated between the General Partner and the Limited Partners on the basis of their respective Percentages.

The General Partner's Minimum Capital Contribution will be determined as of December 31, 2007 and will be an amount equal to:

(a) all costs and expenses previously charged to the General Partner as of that date, plus

(b) the General Partner's good faith estimate of the additional amounts that it will have to contribute in order to fund the Leasehold Acquisition Costs and Drilling Costs expected to be incurred by the Partnership after that date.

The respective Percentages of the General Partner and the Limited Partners will then be determined as of December 31, 2007 based on the relative contributions of the Partners previously made and expected to be made in the future during the remainder of the Partnership's property acquisition and drilling phases. See "GLOSSARY — General Partner's Minimum Capital Contribution", "General Partner's Percentage" and " Limited Partners' Percentage." If the General Partner's estimate of future Leasehold Acquisition Costs and Drilling Costs proves to be lower than the actual amount of such costs and expenses, the excess amounts will be charged to the Partners on the basis of their respective Percentages and the Limited Partners' share will be paid out of their share of Partnership Revenues, Additional Assessments required of them or the proceeds of Partnership borrowings. See "ADDITIONAL FINANCING." If the General Partner's estimate of such costs and expenses proves to be higher than the actual costs and expenses, the General Partner will continue to bear Partnership costs and expenses that would otherwise have been chargeable to the Limited Partners until the total Partnership costs and expenses charged to it (including, without limitation, offering and organizational costs, Operating Expenses, general and administrative overhead costs and reimbursements and Special Production and Marketing Costs as well as Leasehold Acquisition Costs and Drilling Costs) since the formation of the Partnership equals the General Partner's Minimum Capital Contribution. In addition to actual contributions of cash or properties, any Partner will be deemed to have contributed amounts of Partnership Revenues allocated to it which are used to pay its share of Partnership costs and expenses.

The following table presents a summary of the allocation of Partnership costs, expenses and revenues between the General Partner and the Limited Partners:

	General Partner	Limited Partners
COSTS AND EXPENSES		
• Organizational and offering costs of the Partnership and any drilling or income programs in which the Partnership participates as a co-general partner	100%	0%
• All other Partnership Costs and Expenses:		
• Prior to time Limited Partner Capital Contributions are Entirely expended	1%	99%
• After expenditure of Limited Partner Capital Contributions and until expenditure of General Partner's Minimum Capital Contribution	100%	0%
• After expenditure of General Partner's Minimum Capital Contribution	General Partner's Percentage	Limited Partners' Percentage
REVENUES	General Partner's Percentage	Limited Partners' Percentage

COMPENSATION

Supervision of Operations

It is anticipated that the General Partner will operate many of the Partnership Properties during the drilling and production of Partnership Wells. For the General Partner's services performed as operator, the Partnership will compensate the General Partner its pro rata portion of the compensation due to the General Partner under the operating agreements, if any, in effect with respect to such wells or, if none is in effect for such wells, at rates no higher than those normally charged in the same or a comparable geographic area by non-affiliated persons or companies dealing at arm's length.

That portion of the General Partner's general and administrative overhead expense that is attributable to its conduct of the actual and necessary business, affairs and operations of the Partnership will be reimbursed by the Partnership out of Partnership Revenue. The General Partner's general and administrative overhead expenses are determined in accordance with industry practices. The costs and expenses to be allocated include all customary and routine legal, accounting, geological, engineering, travel, office rent, telephone, secretarial, salaries, data processing, word processing and other incidental reasonable expenses necessary to the conduct of the Partnership's business and generated by the General Partner or allocated to it by UNIT, but will not include filing fees, commissions, professional fees, printing costs and other expenses incurred in forming the Partnership or offering interests therein. The amount of such costs and expenses to be reimbursed with respect to any particular period will be determined by allocating to the Partnership that portion of the General Partner's total general and administrative overhead expense incurred during such period which is equal to the ratio of the Partnership's total expenditures compared to the total expenditures by the General Partner for its own account. The portion of such general and administrative overhead expense reimbursement which is charged to the Limited Partners may not exceed an amount equal to 3% of the Aggregate Subscription during the first 12 months of the Partnership's operations, and in each succeeding twelve-month period, the lesser of (a) 2% of the Aggregate Subscription and (b) 10% of the total Partnership Revenue realized in such twelve-month period. Administrative expenses incurred directly by the Partnership, or incurred by the General Partner on behalf of the Partnership and reimbursable to the General Partner, such as legal, accounting, auditing, reporting, engineering, mailing and other such fees, costs and expenses are not considered a part of the general and administrative expense reimbursed to the General Partner and the amounts thereof will not be subject to the limitations described in the preceding sentence.

Purchase of Equipment and Provision of Services

UNIT, through its subsidiary Unit Drilling Company, will probably perform significant drilling services for the Partnership. UNIT also owns Superior Pipeline Company, L.L.C., an Oklahoma limited liability company, which may build or own an interest in certain gathering systems through which a portion of the Partnership's gas production is transported.

These persons are in the business of supplying such equipment and services to non-affiliated parties in the industry and any such equipment and such services will be acquired or provided at prices or rates no higher than those normally charged in the same or comparable geographic area by non-affiliated persons or companies dealing at arms' length. Production purchased by any affiliate of UNIT will be for prices which are not less than the highest posted price (in the case of crude oil) or prevailing price (in the case of natural gas) in the same field or area.

UNIT or one of its affiliates may provide other goods or services to the Partnership in which event the compensation received therefore will be subject to the same restrictions and conditions described above and under "CONFLICTS OF INTEREST" below.

Prior Programs

UNIT was formed in 1986 in connection with a major reorganization and recapitalization whereby UNIT acquired all of the assets and liabilities of all of the limited partnerships formed by UNIT's predecessor, Unit Drilling and Exploration Company (**"UDEC"**), during the period of 1980 through 1983 in exchange for shares of UNIT's common stock and UDEC was merged with a wholly owned subsidiary of UNIT whereby UDEC was the surviving corporation and thereby became a wholly owned subsidiary of UNIT. UNIT has conducted one oil and gas program since the date of its formation, the 1986 Energy Program. The 1986 Energy Program was formed on June 12, 1987 with total subscriptions of one million dollars. The Unit 1986 Employee Oil and Gas Limited Partnership is a co-general partner with Unit Petroleum Company of the 1986 Energy Program. Direct compensation charged to or paid by the partnerships and earned by the General Partners for their services in connection with these programs through September 30, 2006, is set forth below.

Program	Management Fee(1)	Compensation for Supervision and Operation of Productive and Drilling Wells(2)(3)	Reimbursement of General Administrative and Overhead Expense(2)(3)(4)	Fees Received as a Drilling Contractor(2)
1979(***)	150,000	2,833,720	2,539,915	1,835,762
1980	200,000	261,456	1,345,158	1,810,310
1981	1,250,000(5)	329,695	1,892,568	4,047,260
1981-II	450,000	158,406	1,607,706	1,629,201
1982-A	634,200	521,910	1,688,024	4,110,107
1982-B	316,650	331,594	1,224,023	4,945,437
1983-A	50,600	151,289	698,597	695,255
1984	—	340,377	1,197,099	829,503
1984 Employee(*)	—	3,924	5,000	13,452
1985 Employee(*)	—	10,316	—	54,892
1986 Energy Income Fund(**)	—	399,473	1,773,731	109,383
1986 Employee(*)	—	23,505	—	59,446
1987 Employee(*)	—	50,688	—	97,079
1988 Employee(*)	—	93,854	—	112,861
1989 Employee(*)	—	54,536	—	165,436
1990 Employee(*)	—	28,884	—	144,722
1991 Employee(****)	—	572,357	—	144,993
1992 Employee(****)	—	159,914	—	14,934
1993 Employee(****)	—	85,790	—	68,504
1994 Employee(****)	—	122,392	—	42,135
1995 Employee(****)	—	72,331	—	35,903
1996 Employee(****)	—	85,199	—	112,911
1997 Employee(****)	—	75,475	—	170,174
1998 Employee(****)	—	57,689	—	161,343

1999 Employee[****]	—	95,782	—	186,408
Consolidated Program[*][****]	—	420,712	—	798
2000 Employee	—	118,697	—	600,439
2001 Employee	—	35,360	—	363,663
2002 Employee	—	33,149	—	275,071
2003 Employee	—	36,501	—	231,874
2004 Employee	—	9,038	—	546,361
2005 Employee	—	12,132	—	743,190
2006 Employee	—	1,260	—	299,620

(*) Effective December 31, 1993, pursuant to an Agreement and Plan of Merger, this employee partnership was merged with and into the Unit Consolidated Employee Oil and Gas Limited Partnership (the "Consolidated Program"), with the latter being the surviving limited partnership. See Prior Activities.

(**) Formed primarily for purposes of acquiring producing oil and gas properties.

(***) Effective July 1, 2003 this program was dissolved.

(****) Effective December 31, 2002, pursuant to an Agreement and Plan of Merger, this employee partnership was merged with and into the Unit Consolidated Employee Oil and Gas Limited Partnership (the "Consolidated Program"), with the latter being the surviving limited partnership. See Prior Activities.

(1) Paid to both UDEC and a prior Key Employee Exploration Fund as general partners. No management fee was payable to UDEC or any of its affiliates by any of the 1984 - 2006 Employee Programs and no management fee is payable by the Partnership to UNIT or any of its affiliates.

(2) Paid only to UDEC.

(3) In the case of compensation for supervision and operation of productive wells and reimbursement of UNIT's general and administrative overhead expense, the general partners generally were charged with and paid a percentage of such amounts equal to the percentage of partnership revenues being allocated to them.

(4) Although the partnership agreement for each of the 1985-2006 Employee Programs provides that the General Partner is entitled to reimbursement for the general administrative and overhead expenses attributable to each of such programs, the General Partner has to date elected not to seek such reimbursement. However, there can be no assurance that the General Partner will continue to forego such reimbursement in the future.

(5) Includes a special allocation of gross revenues totaling $500,000.

MANAGEMENT

The General Partner

UNIT was formed in 1986 in connection with a major reorganization and recapitalization whereby UNIT acquired all of the assets and liabilities of all of the limited partnerships formed by UNIT's predecessor, UDEC, in exchange for shares of UNIT's common stock in a transaction whereby UDEC became a wholly owned subsidiary of UNIT. UPC was incorporated in the State of Oklahoma on February 9, 1984 as Sunshine Development Corporation (**"SDC"**) and was acquired by UDEC in 1985. The name was changed to Unit Petroleum Company in 1988. On October 8, 1985 pursuant to the terms of a Stock Purchase Agreement," UDEC purchased all of the issued and outstanding stock of SDC whereby SDC became a wholly owned subsidiary of UDEC. On February 1, 1988, pursuant to the terms of an "Amended and Restated Certificate of Incorporation", SDC was renamed Unit Petroleum Company.

UPC's as well as UNIT's, principal office is at 7130 South Lewis Avenue, Suite 1000, Tulsa, Oklahoma 74136 and its telephone number is (918) 493-7700. UNIT through its various subsidiaries is engaged in the onshore contract drilling of oil and gas wells, the exploration for and production of oil and gas and the gathering and transportation of natural gas. Unless the context otherwise requires, references in this Memorandum to UNIT include its predecessor as well as all or any of its subsidiaries.

Officers, Directors and Key Employees

The Partnership will have no directors or officers. The directors of the General Partner are elected annually and serve until their successors are elected and qualified. Directors of UNIT are elected at the Annual Meeting of Shareholders for a staggered term of three years each, or until their successors are duly elected and qualified. The executive officers of the General Partner are elected by and serve at the pleasure of its Board of Directors. The names, ages and respective positions of the directors and executive officers of UNIT are as follows:

Name	Age	Position
King P. Kirchner	79	Director
John G. Nikkel	71	Chairman of the Board
Larry D. Pinkston	52	President, Chief Executive Officer and Director
Mark E. Schell	49	Senior Vice President, Secretary and General Counsel
David T. Merrill	45	Treasurer and Chief Financial Officer
William B. Morgan	62	Director
Don Cook	81	Director

Name	Age	Position
John H. Williams	88	Director
J. Michael Adcock	57	Director
Gary R. Christopher	57	Director
Robert J. Sullivan, Jr.	61	Director

The names, ages and respective positions of the directors and executive officers of UPC are as follows:

Name	Age	Position
Larry D. Pinkston	52	President and Director
Mark E. Schell	49	Senior Vice President, Secretary and General Counsel and Director

Mr. Kirchner, a co-founder of UNIT, has been a director since 1963. He served as Unit's President until November, 1983, as its Chief Executive Officer until June 30, 2001, and served as the Chairman of the Board until July 31, 2003. Mr. Kirchner is a Registered Professional Engineer within the State of Oklahoma, having received degrees in Mechanical Engineering from Oklahoma State University and in Petroleum Engineering, with honors, from the University of Oklahoma. Following graduation, he was employed by Lufkin Manufacturing as a development engineer for hydraulic pumping units. Prior to co-founding Unit, he served in the U.S. Army during the Korean War and after that as vice-president engineering and operations for Woolaroc Oil Company.

Mr. Nikkel joined UNIT as its President, Chief Operating Officer and a director in 1983. He was elected its Chief Executive Officer in July, 2001 and Chairman of the Board in August, 2003. Mr. Nikkel retired as an employee and as the Chief Executive Officer of the company on April 1, 2005. He currently holds the position of Chairman of the Board. From 1976 until January, 1982 when he co-founded Nike Exploration Company, Mr. Nikkel was an officer and director of Cotton Petroleum Corporation, serving as the President of Cotton from 1979 until his departure. Prior to joining Cotton, Mr. Nikkel was employed by Amoco Production Company for 18 years, last serving as Division Geologist for Amoco's Denver Division. Mr. Nikkel presently serves as President and a director of Nike Exploration Company, a family owned oil and gas investment company. From August 16, 2000 until August 23, 2002 Mr. Nikkel, in connection with Unit's investment in the company, also served as a director of Shenandoah Resources Ltd., a Canadian company. Shenandoah Resources Ltd. filed for creditors' protection under The Companies' Creditor Arrangement Act in April 2002 with the Court of Queen's Bench of Alberta, Judicial District of Calgary. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Pinkston joined UNIT in December, 1981. He had served as Corporate Budget Director and Assistant Controller before being appointed Controller in February, 1985. In December, 1986, he was elected Treasurer of Unit 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 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. Effective April 1, 2005, Mr. Pinkston was elected to the additional position of Chief Executive Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

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

Mr. Merrill joined UNIT in August, 2003 as Vice President, Finance. 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. In February, 2004 he was elected to the position of Treasurer and Chief Financial Officer.

Mr. Morgan was elected a director of UNIT in February, 1988. For over five years, Mr. Morgan has been Executive Vice President and General Counsel of St. John Health System, Inc., Tulsa, Oklahoma, and the President of its principal for-profit subsidiary Utica Services, Inc. He was Partner in the law firm of Doerner, Saunders, Daniel & Anderson, Tulsa, Oklahoma, for over twenty years and served as Adjunct Professor of Law at the University of Tulsa College of Law for more than fifteen years, where he taught Securities Regulation. During 1968 and 1969, he served as a Unit States Army Officer in Vietnam and was awarded several medals including the Bronze Star. Mr. Morgan has an undergraduate degree from Muhlenberg College, Allentown, Pennsylvania and a Juris Doctor from the University of Tulsa College of Law. Mr. Morgan is a member of numerous professional and Bar associations and various federal Bars including the United States Supreme Court. He has been listed in *Who's Who in American Law, Who's Who in American Education* and *The Best Lawyers in America*. Mr. Morgan is a Fellow of the American College of Healthcare Executives.

Mr. Cook has served as a director of UNIT since Unit's inception. He was a partner in the accounting firm of Finley & Cook, Shawnee, Oklahoma, from 1950 until 1987, when he retired. Mr. Cook has been designated by the company's board of directors as the Audit Committee's financial expert.

Mr. Williams was elected a director of UNIT in December, 1988. Mr. Williams is engaged in personal investments and has been for more than five years. He was Chairman of the Board and Chief Executive Officer of The Williams Companies, Inc. before retiring in 1978 and continues to serve as an honorary director. Mr. Williams is a director of Apco Argentina, Inc. and also an honorary director of Willbros Group, Inc. He formerly served as a director of Petrolera Entre Lomas S.A. In addition, Mr. Williams is a member of the Tulsa Performing Arts Center Trust.

Mr. Adcock was elected a director of UNIT in December, 1997. He is an attorney and currently manages a private business trust that deals in real estate, oil and natural gas properties and other equity investments. He is Chairman of the Board of Arvest Bank, Shawnee, and a director of Community Health Partners, Inc. Between 1997 and September, 1998 he was the Chairman of the Board of Ameribank and President and Chief Executive Officer of American National Bank and Trust Company of Shawnee, Oklahoma, and Chairman of AmeriTrust Corporation, Tulsa, Oklahoma. Prior to holding these positions, he was engaged in the private practice of law and served as General Counsel for Ameribank Corporation.

Mr. Gary R. Christopher was elected a director of UNIT in July of 2005. Since January 2004, has been engaged in personal investments and consulting. Between August, 1999 and January, 2004, he served as President and Chief Executive Officer of PetroCorp Incorporated (a public oil and gas exploration company), and from March 1996 to August 1999 he served as the Acquisition Coordinator of Kaiser-Francis Oil Company. His other past professional experience includes serving as Vice President of Acquisitions for Indian Wells Oil Company, Senior Vice President and Manager of the Energy Lending Division of First National Bank of Tulsa and from 1991 to 1996 Senior Vice President and Manager of Energy Lending for Bank of Oklahoma. Previous to that, Mr. Christopher worked for Amerada Hess Corporation as a Reservoir Engineer and for Texaco, Inc. as a Production Engineer. Mr. Christopher is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, and the Oklahoma Independent Petroleum Association. Mr. Christopher received a B.S. degree in Petroleum Engineering from the University of Missouri at Rolla. Mr. Christopher is a past Director of the Petroleum Club of Tulsa, Middle Bay Oil Company, Three Tech Energy, PetroCorp Incorporated and a present Director of the Summit Bank of Oklahoma.

Mr. Robert J. Sullivan Jr. was elected a director of UNIT in July of 2005. He is a Principal with Sullivan and Company LLC, a family-owned independent oil and gas exploration and production company founded in 1958. He is also the Founder (1989) and served as Chairman and Chief Executive Officer of Lumen Energy Corporation prior to its sale in 2004. Mr. Sullivan was appointed to Oklahoma Governor Frank Keating's Cabinet as Secretary of Energy in March, 2002. He received a BBA from the University of Notre Dame, and a MBA from the University of Michigan. Mr. Sullivan is a Board Member of the Oklahoma Independent Petroleum Association, Oklahoma Energy Resources Board, St. John Medical Center, St. Joseph Residence, University of Notre Dame Alumni Association, and former Board Member of Catholic Charities and Gatesway Foundation. He also is Trustee for the Monte Cassino Endowment Trust, a Member of the University of Notre Dame, Graduate School Advisory Council and Past Chairman of the following School Boards: Cascia Hall Preparatory School; Monte Cassino School and School of St. Mary.

Prior Employee Programs

Since 1984, UNIT has formed limited partnerships for investment by certain of its key employees and directors that participate with UNIT in its exploration and production operations. The name, month of formation and amount of limited partner capital subscriptions of each of these limited partnerships (the **"Employee Programs"**) are set forth below.

Name	Formed	Limited Partners' Capital Subscriptions
Unit 1984 Employee Oil and Gas Program	April 1984	$ 348,000
Unit 1985 Employee Oil and Gas Limited Partnership	January 1985	$ 378,000
Unit 1986 Employee Oil and Gas Limited Partnership	January 1986	$ 307,000
Unit 1987 Employee Oil and Gas Limited Partnership	March 1987	$ 209,000
Unit 1988 Employee Oil and Gas Limited Partnership	April 29, 1988	$ 177,000
Unit 1989 Employee Oil and Gas Limited Partnership	December 30, 1988	$ 157,000
Unit 1990 Employee Oil and Gas Limited Partnership	January 19, 1990	$ 253,000
Unit 1991 Employee Oil and Gas Limited Partnership	January 7, 1991	$ 263,000
Unit 1992 Employee Oil and Gas Limited Partnership	January 23, 1992	$ 240,000
Unit 1993 Employee Oil and Gas Limited Partnership	January 21, 1993	$ 245,000
Unit 1994 Employee Oil and Gas Limited Partnership	January 19, 1994	$ 284,000
Unit 1995 Employee Oil and Gas Limited Partnership	March 7, 1995	$ 454,000
Unit 1996 Employee Oil and Gas Limited Partnership	February 5, 1996	$ 437,000
Unit 1997 Employee Oil and Gas Limited Partnership	February 4, 1997	$ 413,000
Unit 1998 Employee Oil and Gas Limited Partnership	February 19, 1998	$ 471,000
Unit 1999 Employee Oil and Gas Limited Partnership	February 22, 1999	$ 188,000
Unit 2000 Employee Oil and Gas Limited Partnership	February 22, 2000	$ 199,000
Unit 2001 Employee Oil and Gas Limited Partnership	February 9, 2001	$ 370,000
Unit 2002 Employee Oil and Gas Limited Partnership	January 30, 2002	$ 457,000
Unit 2003 Employee Oil and Gas Limited Partnership	January 31, 2003	$ 284,000
Unit 2004 Employee Oil and Gas Limited Partnership	February 18, 2004	$ 434,000

Unit 2005 Employee Oil and Gas Limited Partnership	January 26, 2005	$ 496,000
Unit 2006 Employee Oil and Gas Limited Partnership	February 2, 2006	$ 767,000

One-half of the capital subscriptions from all limited partners were required to be paid in the 1984 Employee Program, three-fourths of the capital subscriptions from all limited partners were required to be paid in the 1985 Employee Program and the 1986 Employee Program. All of the capital subscriptions from all limited partners, including those shown below, were required to be paid in the 1987 through 2006 Employee Programs. The capital subscriptions of the following limited partners to the 2004, 2005 and 2006 Employee Programs were as shown below:

Subscriber	Position with UNIT	Amount of Capital Subscription		
		2004	2005	2006
King P. Kirchner[(1)]	Director	$ 40,000	$ 40,000	$ 40,000
John G. Nikkel[(2)]	Chairman of the Board	$200,000	$150,000	$ 200,000

(1) Mr. Kirchner invested in these programs through the King P. Kirchner Revocable Trust as permitted by the limited partnership agreement of those Employee Programs.

(2) Mr. Nikkel invested in programs both directly and through Nike Exploration Company. Mr. Nikkel and members of his family are the sole owners of Nike Exploration Company. The amounts invested directly and indirectly through Nike Exploration Company in the 2004, 2005 and 2006 Employee Programs by Mr. Nikkel were as follows:

Employee Program	Mr. Nikkel Directly	Nike Exploration Company
2004	$ 100,000	$ 100,000
2005	$ 150,000	$ 0
2006	$ 200,000	$ 0

Ownership of Common Stock

UNIT's Common Stock is listed on the New York Stock Exchange as reported on the Composite Tape. On December 27, 2006 there were 46,283,390 shares outstanding.

As of December 27, 2006, the directors and officers of UNIT owned of record or beneficially owned shares of UNIT Common Stock as follows:

Name	Amount of Beneficial Ownership[(1)]	% of Outstanding[(1)]
King P. Kirchner	152,220	*
John H. Williams	22,000	*
Don Cook	34,618	*
John G. Nikkel	300,376	*
Larry D. Pinkston	90,739	*
Mark E. Schell	80,916	*
William B. Morgan	28,500	*
J. Michael Adcock	31,941	*
Gary R. Christopher	6,500	*
Robert J. Sullivan, Jr.	3,500	*
David T. Merrill	10,627	*

All Officers and Directors as a Group	761,937(2)(3)(4)(5)	1.62%

* Less than 1%

(1) The number of shares includes the shares presently issued and outstanding plus the number of shares which any owner has the right to acquire within 60 days after December 27, 2006, pursuant to the exercise of currently exercisable stock options. For purposes of calculating the percent of the shares outstanding held by each owner, the total number of shares excludes the shares which all other persons have the right to acquire within 60 days after December 27, 2006 pursuant to the exercise of currently exercisable stock options.

(2) Includes shares of common stock held under UNIT's 401(k) thrift plan as of December 27, 2006 for the account of: David T. Merrill, 578; Larry D. Pinkston, 4,509; and Mark E. Schell, 32,287.

(3) Includes unexercised stock options granted under UNIT's Non-Employee Directors' Stock Option Plan to each of the following, all of which are currently exercisable at the discretion of the holder: J. Michael Adcock, 14,000; Don Cook, 27,000; William B. Morgan, 23,500; John H. Williams, 21,000; John G. Nikkel, 7,000; Gary R. Christopher 3,500; Robert J. Sullivan, Jr. 3,500; and King P. Kirchner 17,500 shares and all Non-Employee Directors as a group, 117,000.

(4) Includes unexercised stock options granted under UNIT's Amended and Restated Stock Option Plan to each of the following, all of which are exercisable within 60 days from December 27, 2006 at the discretion of the holder: David T. Merrill, 6,800; Larry D. Pinkston, 35,500; and Mark E. Schell, 33,400.

(5) Of the shares shown, Mr. J. Michael Adcock is deemed to be the beneficial owner of 17,491 shares by virtue of his position as one of three trustees of the Don Bodard 1995 Revocable Trust.

Interest of Management in Certain Transactions

Reference is made to "COMPENSATION" for a discussion of the compensation for supervision and operation of productive wells and the reimbursement of overhead expenses attributable to the Partnership's operations to which UNIT is entitled under the terms of the Partnership Agreement.

CONFLICTS OF INTEREST

There will be situations in which the individual interests of the General Partner and the Limited Partners will conflict. Although the General Partner is obligated to deal fairly and in good faith with the Limited Partners and conduct Partnership operations using the standards of a prudent operator in the oil and gas industry, such conflicts may not in every instance be resolved to the maximum advantage of the Limited Partners. Certain circumstances which will or may involve potential conflicts of interest are as follows:

- The General Partner currently manages and in the future will sponsor and manage oil and natural gas drilling programs similar to the Partnership.
- The General Partner will decide which prospects the Partnership will acquire.
- The General Partner will act as operator for Partnership Wells and will, through its affiliates, furnish drilling and/or marketing services with respect to Partnership Wells, the terms of which have not been negotiated by non-affiliated persons.
- The General Partner is a general partner of numerous other partnerships, and owes duties of good faith dealing to such other partnerships.
- The General Partner and its affiliates engage in drilling, operating and producing activities for other partnerships.

Acquisition of Properties and Drilling Operations

With certain limited exceptions it is anticipated that the Partnership will participate in each producing property, if any, acquired by the General Partner and in the drilling of each of the wells, if any, commenced by the General Partner for its own account during the period commencing January 1, 2007, or from the formation of the Partnership if subsequent to January 1, 2007, through December 31, 2007 except for wells:

(i) drilled outside the 48 contiguous United States;

(ii) drilled as part of secondary or tertiary recovery operations which were in existence prior to formation of the Partnership;

(iii) drilled by third parties under farm-out or similar arrangements with UNIT or the General Partner or whereby UNIT or the General Partner may be entitled to an overriding royalty, reversionary or other similar interest in the production from such wells but is not obligated to pay any of the Drilling Costs thereof;

(iv) acquired by UNIT or the General Partner through the acquisition by UNIT or the General Partner of, or merger of UNIT or the General Partner with, other companies; or

(v) with respect to which the General Partner does not believe that the potential economic return therefrom justifies the costs and participation by the Partnership.

As a result, the Partnership may have an interest in wells located on prospects on which producing wells have been drilled by UNIT or the General Partner in prior years. Likewise, it is possible that the Partnership will participate in the drilling of initial wells on prospects on which some or all of the development or offset wells will be drilled in years subsequent to 2007. In the latter case, the Partnership would have no right to participate in the drilling of such development or offset wells.

Sometimes UNIT will agree to participate in drilling operations on a prospect which it may not believe are fully warranted from an economic standpoint if it believes that such participation is necessary for, or will significantly increase its chances of, obtaining a contract to drill the well with one of its drilling rigs and the revenues from the contract make the economics of the entire arrangement desirable from UNIT's standpoint. In such an instance, the Partnership would not be entitled to any of the drilling contract revenues so the General Partner will not cause the Partnership to participate in such a well. However, an analysis of the economic potential of any proposed well is a very inexact science and wells which have a very high potential commonly prove to be dry or only marginally profitable and occasionally a well with apparently very little promise may prove to be very profitable. Thus, there can be no assurance that the General Partner will always make the most profitable decision from the Partnership's standpoint in determining in which of such potential wells the Partnership should or should not participate.

Because the Partnership will acquire an interest only in those properties comprising the spacing unit on which each Partnership Well is located, it will not be entitled to participate in other wells drilled by the General Partner, UNIT or any of its affiliates in the same prospect area unless the drilling of those wells commences during the period from January 1, 2007, or from the formation of the Partnership if subsequent to January 1, 2007, through December 31, 2007. If the size of a spacing unit in which the Partnership has an interest is reduced, the Partnership will have no interest in any additional well drilled on the property comprising the original spacing unit unless it is commenced during the period from January 1, 2007, or from the formation of the Partnership if subsequent to January 1, 2007, through December 31, 2007. Likewise the Partnership would have no interest in any increased density wells drilled on the original spacing unit unless such wells were drilled during 2007. In addition, if additional interests are acquired in wells participated in by the Partnership after 2007, the Partnership will generally not be entitled to participate in the acquisition of such additional interests. Management believes that the apparent conflicts of interest arising from these situations are mitigated by the fact that the Partnership is expected to participate in all of UNIT's drilling operations (with the exceptions noted above) conducted during the period. Thus, there is little opportunity for the General Partner to selectively choose Partnership drilling locations for the purpose of proving up other properties of UNIT or its affiliates in which the Partnership has no interest. Further, the Partnership will benefit in many instances by its participation in the drilling of wells located on prospects previously proved up by drilling operations conducted by UNIT prior to formation of the Partnership.

Participation in UNIT's Drilling or Income Programs

If UNIT forms any drilling or income programs in 2007, it is anticipated that the Partnership will serve as a co-general partner with UNIT in any such drilling or income programs, or both. As the other co-general partner of any such drilling or income program, UNIT would have exclusive management and control over the business, operations and affairs of the drilling or income program. Conflicts of interest may arise between the limited partners and the general partners of such drilling or income program and it is possible that UNIT may elect to resolve those conflicts in favor of the limited partners. Further, if any such drilling or income program is offered publicly, the program agreement will be required to contain a number of provisions concerning the conduct of program operations and handling conflicts of interests required by the Guidelines for the Registration of Oil and Gas Programs adopted by the North American Securities Administrators Association, Inc. Such provisions may significantly reduce the flexibility of UNIT in managing such programs or may affect the profitability of the program operations or the transactions between the general partners and the program.

Transfer of Properties

The General Partner or its affiliates are authorized to transfer interests in oil and gas properties to the Partnership, in which case the General Partner or its affiliate will receive an amount equal to the Leasehold Acquisition Costs attributable to the interests being acquired by the Partnership in the spacing unit on which the Partnership Well is located or is to be drilled. The amount of the Leasehold Acquisition Costs attributable to the fractional undivided interest in a property transferred to the Partnership by the General Partner or any affiliate shall not be reduced or offset by the amount of any gain or profit the General Partner or its affiliate might have realized by any prior sale or transfer of a fractional undivided interest in the property to an unaffiliated third party for a price in excess of the portion of the Leasehold Acquisition Costs of the property that is attributable to the transferred interest. The Partnership will not be reimbursed for or refunded any Leasehold Acquisition Costs if the size of a spacing unit on which a Partnership Well is located or drilled is reduced even though the Partnership will have no interest in any subsequent wells drilled on the area encompassed by the original spacing unit unless they are commenced during 2007.

A sale, transfer or conveyance to the Partnership of less than all of the ownership of the General Partner or its affiliates in any interest or property is prohibited unless:

(1) the interest retained by the General Partner or its affiliates is a proportionate working interest;

(2) the obligations of the Partnership with respect to the properties will be substantially the same proportionately as those of the General Partner or its affiliates at the time it acquired the properties; and

(3) the Partnership’s interest in revenues will not be less than the proportionate interest therein of the General Partner or its affiliates when it acquired the properties.

With respect to the General Partner or its affiliates’ remaining interest, it may retain such interest for its own account or it may sell, transfer, farm-out or otherwise convey all or a portion of such remaining interest to non-affiliated industry members, which may occur either before or after the transfer of the interests in the same properties to the Partnership. The General Partner or its affiliates may realize a profit on the interests or may be carried to some extent with respect to its cost obligations in connection with any drilling on such properties and any such profit or interests will be strictly for the account of the General Partner or its affiliates and the Partnership will have no claim with respect thereto. The General Partner or its affiliates may not retain any overrides or other burdens on the property conveyed to the Partnership (other than overriding royalty interests granted to geologists and other persons employed or retained by the General Partner or its affiliates) and may not enter into any farm-out arrangements with respect to its retained interest except to non-affiliated third parties or other programs managed by the General Partner or its affiliates.

Partnership Assets

The General Partner will not take any action with respect to assets or property of the Partnership which does not benefit primarily the Partnership as a whole. The General Partner will not utilize the funds of the Partnership as compensating balances for the benefit of the General Partner or its affiliates. All benefits from marketing arrangements or other relationships affecting property of the Partnership will be fairly and equitably apportioned according to the respective interests of the Partnership and the General Partner.

The Partnership Agreement provides that when the Partnership is terminated, there will be an accounting with respect to its assets, liabilities and accounts. The Partnership’s physical property and its oil and gas properties may be sold for cash. Except in the case of an election by the General Partner to terminate the Partnership before the tenth anniversary of the Effective Date, Partnership Properties may be sold to the General Partner or any of its affiliates for their fair market value as determined in good faith by the General Partner.

Transactions with the General Partner or Affiliates

UNIT provides through its subsidiary Unit Drilling Company contract drilling services in the ordinary course of its business. UNIT also owns Superior Pipeline Company, L.L.C. which is engaged in the business of buying and building gas gathering systems. It is anticipated that the Partnership will obtain services, equipment and supplies from one or all of such persons. In addition, UNIT may supply other goods or services to the Partnership. The terms of any contracts or agreements between the Partnership and UNIT or any affiliate will be no less favorable to the Partnership than those of comparable contracts or agreements entered into, and will be at prices not in excess of (or in the case of purchases of production, less than) those charged in the same geographical area, by non-affiliated persons or companies dealing at arm's length.

For its services as a drilling contractor, Unit Drilling Company will charge the Partnership on either a daywork (a specified per day rate for each day a drilling rig is on the drill site), a footage (a specified rate per foot drilled) or a turnkey (specified amount for drilling the well) basis. The rate charged by Unit Drilling Company for such services will be the same as those offered to unaffiliated third parties in the same or similar geographic areas.

Right of Presentment Price Determination

Under the terms of the Partnership Agreement, a Limited Partner can, subject to certain conditions, require the General Partner to purchase his or her Units at a price determined by the application of a stated formula to the estimated future net revenues attributable to the Partnership's estimated proved reserves. See "TERMS OF THE OFFERING — Right of Presentment." It is anticipated that if an independent engineering firm makes an evaluation of the proved reserves of the Partnership, the result of that evaluation will be used in determining the price to be paid to a Limited Partner exercising his or her right of presentment. However, if no such independent evaluation is made, the right of presentment purchase price will be determined by using the proved reserves and future net revenue estimates of the technical staff of the General Partner.

Receipt of Compensation Regardless of Profitability

The General Partner is entitled to receive its fees and other compensation and reimbursements from the Partnership regardless of whether the Partnership operates at a profit or loss. See "PARTICIPATION IN COSTS AND REVENUES" and "COMPENSATION." Such fees, compensation and reimbursements will decrease the Limited Partners' share of any profits generated by operations of the Partnership or increase losses if such operations should prove unprofitable.

Legal Counsel

Conner & Winters, LLP serves as special legal counsel for the General Partner. Such firm has performed legal services for the General Partner and UNIT and is expected to render legal services to the Partnership. Although such firm has indicated its intention to withdraw from representation of the Partnership if conflicts of interest do in fact arise, there can be no assurance that representation of both the General Partner or UNIT and the Partnership by such firm will not be disadvantageous to the Partnership.

FIDUCIARY RESPONSIBILITY

General

Under Oklahoma law, the General Partner will have a fiduciary duty to the Limited Partners and consequently must exercise good faith, fairness and loyalty in the handling of the Partnership's affairs. The General Partner must provide Limited Partners (or their representatives) with timely and full information concerning matters affecting the business of the Partnership. Each Limited Partner may inspect the Partnership's books and records on reasonable prior notice. The nature of the fiduciary duties of general partners is an evolving area of law and prospective investors who have questions concerning the duties of the General Partner should consult with their counsel.

Regardless of the fiduciary obligations of the General Partner, the General Partner, UNIT or its affiliates, subject to any restrictions or requirements set forth in the Agreement, may:

- engage independently of the Partnership in all aspects of the oil and gas business, either for their own accounts or for the accounts of others;
- sell interests in oil and gas properties held by them to, purchase oil and gas production from, and engage in other transactions with, the Partnership;
- serve as general partner of other oil and gas drilling or income partnerships, including those which may be in competition with the Partnership; and
- engage in other activities that may involve conflicts of interest.

See "CONFLICTS OF INTEREST." Thus, unlike the strict duty of a fiduciary who must act solely in the best interests of his or her beneficiary, the Agreement permits the General Partner to consider, among other things, the interests of other partnerships sponsored by the General Partner, UNIT or its affiliates in resolving investment and other conflicts of interest. The foregoing provisions permit the General Partner to conduct its own operations and to act as the general partner of more than one similar partnership or investment program and for the Partnership to benefit from its experience resulting therefrom, but relieves the General Partner of the strict fiduciary duty of a general partner acting as such for only one investment program at a time. These provisions are primarily intended to reconcile the applicable duties under Oklahoma law with the fact that the General Partner will manage and administer its own oil and gas operations and a number of other oil and gas investment programs with which possible conflicts of interests may arise and resolve such conflicts in a manner consistent with the expectation of the investors in all such programs, the General Partner's fiduciary duties and customary business practices and statutes applicable thereto.

Liability and Indemnification

The Agreement provides that the General Partner will perform its duties in an efficient and businesslike manner with due caution and in accordance with established practices of the oil and gas industry. The Agreement further provides that the General Partner and its affiliates will not be liable to the Partnership or the Partners, and will be indemnified by the Partnership, for any expense (including attorney fees), loss or damage incurred by reason of any act or omission performed or omitted in good faith in a manner reasonably believed by the General Partner or its affiliates to be within the scope of authority and in the best interest of the Partnership or the Partners unless the General Partner or its affiliates is guilty of gross negligence or willful misconduct. While not totally certain under Oklahoma law, absent specific provisions in the partnership agreement to the contrary, a general partner of a limited partnership may be liable to its limited partners if it fails to conduct the partnership affairs with the same amount of care which ordinarily prudent persons would use in similar circumstances. Consequently, the Agreement may be viewed as requiring a lesser standard of duty and care than what Oklahoma law might otherwise require of the General Partner.

Any claim against the Partnership for indemnification must be satisfied only out of Partnership assets including insurance proceeds, if any, and none of the Limited Partners will have personal liability therefore.

The Limited Partners may have more limited rights of action than they would have absent the liability and indemnification provisions above. Moreover, indemnification enforced by the General Partner under such provisions will reduce the assets of the Partnership. It should be noted, however, that it is the position of the Securities and Exchange Commission (**"Commission"**) that any attempt to limit the liability of a general partner or to indemnify a general partner under the federal securities laws is contrary to public policy and, therefore, unenforceable. The General Partner has been advised of the position of the Commission.

Generally, the Limited Partners' remedy for the General Partner's breach of a fiduciary duty will be to bring a legal action against the General Partner to recover any damages, generally measured by the benefits earned by the General Partner as a result of the fiduciary breach. Additionally, Limited Partners may also be able to obtain other forms of relief, including injunctive relief. The Act provides that a limited partner may bring an action in the name of a limited partnership (a partnership derivative action) to recover a judgment in its favor if general partners with authority to do so have refused to bring the action or if an effort to cause such general partners to bring the action is not likely to succeed.

PRIOR ACTIVITIES

UNIT has been engaged in oil and gas exploration and development operations since late 1974 and has conducted oil and gas drilling programs using the limited partnership format since 1979. The following table depicts the drilling results achieved as of September 30, 2006 by UNIT during each year since 1975. Because of the unpredictability of oil and gas exploration in general, such results should not be considered indicative of the results that may be achieved by the Partnership.

	Gross Wells[2]				Net Wells[3]			
Year Ended July 31[1]	Total	Oil	Gas	Dry	Total	Oil	Gas	Dry
1975 Exploratory	2	0	2	0	.01	0	.01	0
Development	4	0	2	2	.07	0	.03	.04
	6	0	4	2	.08	0	.04	.04
1976 Exploratory	1	0	0	1	.01	0	0	.01
Development	8	0	6	2	.29	0	.28	.01
	9	0	6	3	.30	0	.28	.02
1977 Exploratory	9	0	3	6	1.50	0	.45	1.05
Development	16	0	9	7	2.00	0	.70	1.30
	25	0	12	13	3.50	0	1.15	2.35
1978 Exploratory	8	1	1	6	1.17	.34	.15	.68
Development	26	0	13	13	2.64	0	.76	1.88
	34	1	14	19	3.81	.34	.91	2.56
1979 Exploratory	10	0	5	5	1.40	0	.76	.64
Development	16	1	8	7	1.99	.06	.95	.98
	26	1	13	12	3.39	.06	1.71	1.62
1980 Exploratory	1	0	1	0	1.28	0	.23	1.05
Development	10	0	8	2	3.13	0	.85	2.28
	11	0	9	2	4.41	0	1.08	3.33
1981 Exploratory	14	1	4	9	1.12	.02	.16	.94
Development	66	18	29	19	7.38	2.96	1.77	2.65
Total	80	19	33	28	8.50	2.98	1.93	3.59
1982 Exploratory	40	5	9	26	3.39	.60	.32	2.47
Development	100	22	51	27	11.70	4.70	2.71	4.29
Total	140	27	60	53	15.09	5.30	3.03	6.76
1983 Exploratory	6	2	0	4	1.31	.72	0	.59

Development	72	18	26	28	8.01	3.45	1.17	3.39
Total	78	20	26	32	9.32	4.17	1.17	3.98
1984 Exploratory	2	1	1	0	.52	.49	.03	0
Development	50	15	22	13	6.81	3.42	2.74	.65
Total	52	16	23	13	7.33	3.91	2.77	.65

Year Ended July 31[1]	Gross Wells[2] Total	Oil	Gas	Dry	Net Wells[3] Total	Oil	Gas	Dry
1985 Exploratory	0	0	0	0	0	0	0	0
Development	38	11	16	11	8.32	2.89	2.39	3.04
Total	38	11	16	11	8.32	2.89	2.39	3.04
1986 Exploratory	0	0	0	0	0	0	0	0
Development	21	4	6	11	3.85	.81	1.01	2.03
Total	21	4	6	11	3.85	.81	1.01	2.03
1987 Exploratory	0	0	0	0	0	0	0	0
Development	46	23	10	13	11.91	7.95	1.76	2.34
Total	46	23	10	13	11.91	7.95	1.76	2.34
1988 Exploratory	0	0	0	0	0	0	0	0
Development	39	20	10	9	22.56	14.77	4.05	3.74
Total	39	20	10	9	22.56	14.77	4.05	3.74
1989 Exploratory	3	0	1	2	1.97	0	.47	1.50
Development	40	12	15	13	18.83	8.81	4.13	5.89
Total	43	12	16	15	20.80	8.81	4.60	7.39
1990 Exploratory	5	0	2	3	1.22	0	.12	1.10
Development	35	11	14	10	16.53	8.38	3.52	4.63
Total	40	11	16	13	17.75	8.38	3.64	5.73
1991 Exploratory	4	0	0	4	.82	0	0	.82
Development	28	10	9	9	15.88	8.61	3.91	3.36
Total	32	10	9	13	16.70	8.61	3.91	4.18
1992 Exploratory	0	0	0	0	0	0	0	0
Development	18	1	11	6	5.81	1.00	3.33	1.48
Total	18	1	11	6	5.81	1.00	3.33	1.48
1993 Exploratory	1	0	0	1	.10	0	0	.10

Development	16	9	6	1	12.48	8.98	3.32	.18
Total	17	9	6	2	12.58	8.98	3.32	.28
1994 Exploratory	3	0	1	2	1.71	0	.95	.76
Development	57	5	40	12	25.79	4.75	14.14	6.90
Total	60	5	41	14	27.50	4.75	15.09	7.66
1995 Exploratory	0	0	0	0	0	0	0	0
Development	45	15	24	6	14.94	4.67	8.04	2.23
Total	45	15	24	6	14.94	4.67	8.04	2.23
1996 Exploratory	0	0	0	0	0	0	0	0
Development	70	10	51	9	32.09	7.61	20.09	4.39
Total	70	10	51	9	32.09	7.61	20.09	4.39
1997 Exploratory	2	0	0	2	2.00	0	0	2.00
Development	80	8	58	14	35.94	4.35	23.29	8.30
Total	82	8	58	16	37.94	4.35	23.29	10.30

Year Ended July 31[1]	Gross Wells[2] Total	Oil	Gas	Dry	Net Wells[3] Total	Oil	Gas	Dry
1998 Exploratory	2	0	1	1	.63	0	.375	.26
Development	76	3	52	21	30.17	.31	18.750	11.11
Total	78	3	53	22	30.80	.31	19.125	11.37
1999 Exploratory	0	0	0	0	0	0	0	0
Development	51	1	42	8	21.8	.4	17.4	4.0
Total	51	1	42	8	21.8	.4	17.4	4.0
2000 Exploratory	2	0	2	0	1.72	0	1.72	0
Development	98	7	73	18	38.37	1.45	28.55	8.37
Total	100	7	75	18	40.09	1.45	30.27	8.37
2001 Exploratory	3	0	0	3	2.03	0	0	2.03
Development	123	7	94	22	49.94	1.08	34.12	14.74
Total	126	7	94	25	51.97	1.08	34.12	16.77
2002 Exploratory	6	0	2	4	1.34	0	.90	.44
Development	91	4	63	24	47.15	1.92	29.71	15.52
Total	97	4	65	28	48.49	1.92	30.61	15.96
2003 Exploratory	4	1	3	0	2.40	.20	2.20	0
Development	145	5	119	21	59.17	2.13	44.31	12.73
Total	149	6	122	21	61.57	2.33	46.51	12.73
2004 Exploratory	14	1	7	6	6.29	.98	2.75	2.56
Development	156	18	114	24	65.11	7.33	45.28	12.50
Total	170	19	121	30	71.40	8.31	48.03	15.06
2005 Exploratory	8	1	5	2	3.91	.32	1.59	2.00
Development	184	17	154	13	68.37	5.68	56.93	5.76
Total	192	18	159	15	72.28	6.00	58.52	7.76
Period of January 1, 2006 to September 30, 2006								

2006 Exploratory	8	0	4	4	4.01	0	2.76	1.25
Development	170	9	142	19	58.26	1.94	48.55	7.77
Total	178	9	146	23	62.27	1.94	51.31	9.02

(1) Except as indicated, the figures used in this table relate to wells drilled and completed during each of the 12 month periods ended July 31 or December 31, as the case may be. Oil wells and gas wells shown include both producing wells and wells capable of production.

(2) "Gross Wells" refers to the total number of wells in which there was participation by UNIT.

(3) "Net Wells" refers to the aggregate leasehold working interest of UNIT in such wells. For example, a 50% leasehold working interest in a well drilled represents 1.0 Gross Well, but a .50 Net Well.

Prior Employee Programs

During the period of 1979 to 1983, persons who were designated key employees of UNIT by its board of directors participated in the Unit Key Employee Exploration Funds (the **"Funds"**). These Funds were formed as general partnerships for the purpose of participating in 10% of all of the exploration and development operations conducted by UNIT during a specified period. Except for the Fund formed in 1983, each of the prior Funds served as one of the general partners in at least one of the prior drilling programs sponsored by UNIT and was allocated 10% of the expenses and revenues allocable to the general partners as a group. In each of these Funds the costs charged to it in connection with its operations were financed with the proceeds of bank borrowings and out of the Funds' share of revenues.

The 1983 Fund served as the sole capital limited partner in the Unit 1983-A Oil and Gas Program and as such made no contribution to the capital of that program and shared in 10% of the costs and revenues otherwise allocable to the General Partner after the distributions to the General Partner from the program equaled the amount of its contributions thereto plus UNIT's interest costs with respect to the unrecovered amount of its contributions.

Because of the differences in structure, format and plan of operations between the prior Funds and the Partnership and because of the uncertainties which are inherent in oil and gas operations generally, the results achieved by the prior Funds should not be considered indicative of the results the Partnership may achieve.

For each year from 1984 through 2006, a separate Employee Program was formed as an Oklahoma limited partnership with UNIT or UPC as its sole general partner (UPC now serves as the sole general partner of each of these Employee Programs) and with eligible employees and directors of UNIT and its subsidiaries who subscribed for units therein as the limited partners. Each Employee Program participated on a proportionate basis (to the extent of 10% of the General Partner's interest in each case except for the 1986 and 1987 Employee Programs, in which case the percentage participation was 15% and the 1992-2001 Employee Programs, in which case the percentage was 5% and the 2002 and 2003 Employee Programs in which case the percentage was 2 1/2% and 2004, 2005 and 2006 Employee Program in which case the percentage was 1%) in all of UNIT's oil and gas exploration and development operations conducted during the calendar year for which the program was formed beginning with its date of formation if it was formed after January 1. Although the terms and provisions of these Employee Programs are virtually identical to those of the Partnership, because of the unpredictability of oil and gas exploration and development in general, the results for the Employee Programs shown below should not be considered indicative of the results that may be achieved by the Partnership.

As noted above, the Funds and the Employee Programs have participated in a specified percentage (ranging from 1% to 15%, depending on the program) of virtually all of UNIT's or the General Partner's exploration and development operations conducted since the latter half of 1979. Thus, the drilling results of these partnerships would be proportionate to those drilling results of UNIT for the periods beginning after the fiscal year ended July 31, 1979 shown above.

Results of the Prior Oil and Gas Programs

In each of the General Partner's prior oil and gas programs other than the Unit 1983-A Oil and Gas Program and the Unit 1984 Oil and Gas Limited Partnership, one of the prior Funds also served as a general partner. The 1983 Fund served as the sole capital limited partner of the Unit 1983-A Oil and Gas Program and the 1984 Employee Program serves as a general partner of the Unit 1984 Oil and Gas Limited Partnership. The Unit 1979 Oil and Gas Program was the first limited partnership drilling program of which UNIT was a sponsor. The revenue sharing terms of the 1979 Program was generally 70% to the limited partners and 30% to the general partners until 150% program payout at which time the revenues were to be shared 55% to the limited partners and 45% to the general partners. The 1979 Program was dissolved effective July 1, 2003. The revenue sharing terms of the Unit 1980 Oil and Gas Program were generally 60% to the limited partners and 40% to the general partners. The revenue sharing terms of the Unit 1981 Oil and Gas Program were generally 70% to the limited partners and 30% to the general partners until program payout and 50% to the limited partners and 50% to the general partners thereafter. The revenue sharing terms of the Unit 1981-II Oil and Gas Program, the Unit 1982-A Oil and Gas Program and the Unit 1982-B Oil and Gas Program (60% to the limited partners and 40% to the general partners) were substantially the same as those of the Unit 1983-A Oil and Gas Program and the Unit 1984 Oil and Gas Limited Partnership (65% to the limited partners and 35% to the general partner) except that the general partners' cost percentage and the general partners' revenue share in each of those prior programs could not be less than 25%. The following tables depict the drilling results at September 30, 2006, and the economic results at September 30, 2006 of prior oil and gas programs and the 1984-2006 Employee Programs. On September 12, 1986, in connection with a major restructuring and recapitalization, UNIT acquired all of the assets and liabilities of the programs formed during 1980 through 1983 and these programs have now been dissolved. Effective December 31, 1993, pursuant to an Agreement and Plan of Merger, dated as of December 28, 1993, all of the assets and all of the liabilities of the 1984, 1985, 1986, 1987, 1988, 1989 and 1990 Employee Programs were merged with and consolidated into a new Employee Program called the Unit Consolidated Employee Oil and Gas Limited Partnership, an Oklahoma Limited Partnership which was formed November 30, 1993 (the **"Consolidated Program"**). Effective December 31, 2002, pursuant to an Agreement and Plan of Merger, dated December 27, 2002, all of the assets and all of the liabilities of the 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, and 1999 Employee Programs were merged with and consolidated into to the Consolidated Program. The Consolidated Program holds no assets other than those acquired in the mergers with the 1984 through 1999 Employee Programs. All of the Employee Programs formed since 2000 continue in existence. Certain of these programs have not completed all of their drilling and development operations. Moreover, because of the unpredictability of oil and gas exploration and development in general, the results shown below should not be considered indicative of the results that may be achieved by the Partnership.

DRILLING RESULTS

As of September 30, 2006

Programs		Gross Wells				Net Wells			
		Total	Oil	Gas	Dry	Total	Oil	Gas	Dry
1979(1)									
	Exploratory Wells	6	0	2	4	2.43	0.00	0.65	1.78
	Development Wells	21	16	1	4	17.28	14.14	0.03	3.11
	Total	27	16	3	8	19.71	14.14	0.68	4.89
1980(2)									
	Exploratory Wells	15	2	5	8	5.65	0.50	2.14	3.01
	Development Wells	32	5	15	12	12.77	1.17	5.75	5.85
	Total	47	7	20	20	18.42	1.67	7.89	8.86
1981(2)									
	Exploratory Wells	11	1	4	6	4.61	0.33	0.88	3.40
	Development Wells	67	14	34	19	21.77	5.03	6.61	10.13
	Total	78	15	38	25	26.38	5.36	7.49	13.53
1981-II(2)									
	Exploratory Wells	13	1	5	7	5.21	0.25	1.12	3.84
	Development Wells	45	3	29	13	9.07	0.69	4.78	3.60
	Total	58	4	34	20	14.28	0.94	5.90	7.44
1982-A(2)									
	Exploratory Wells	11	3	1	7	3.55	0.78	0.00	2.77
	Development Wells	69	23	22	24	25.22	13.09	3.59	8.54
	Total	80	26	23	31	28.77	13.87	3.59	11.31
1982-B(2)									
	Exploratory Wells	4	1	1	2	2.28	0.80	0.08	1.40
	Development Wells	41	16	9	16	18.60	9.47	1.01	8.12
	Total	45	17	10	18	20.88	10.27	1.09	9.52
1983-A(2)									
	Exploratory Wells	1	1	0	0	1.00	1.00	0.00	0.00
	Development Wells	26	14	10	2	6.60	4.39	1.27	0.94
	Total	27	15	10	2	7.60	5.39	1.27	0.94
1984									
	Exploratory Wells	0	0	0	0	0.00	0.00	0.00	0.00
	Development Wells	21	1	10	10	5.89	.38	3.08	2.43
	Total	21	1	10	10	5.89	.38	3.08	2.43

(1) Effective July 1, 2003 this program was dissolved.

(2) On September 12, 1986, Unit acquired all of the assets and liabilities of this Program and the Program has been dissolved.

EMPLOYEE PROGRAMS

As of September 30, 2006

Programs		Gross Wells Total	Gross Wells Oil	Gross Wells Gas	Gross Wells Dry	Net Wells Total	Net Wells Oil	Net Wells Gas	Net Wells Dry
1984[1]									
	Exploratory Wells	0	0	0	0	0.00	0.00	0.00	0.00
Empl.									
	Development Wells	25	4	12	9	.14	.02	.06	.06
	Total	25	4	12	9	.14	.02	.06	.06
1985[1]									
	Exploratory Wells	0	0	0	0	0.00	0.00	0.00	0.00
Empl.									
	Development Wells	30	8	10	12	.38	.12	.08	.18
	Total	30	8	10	12	.38	.12	.08	.18
1986[1]									
	Exploratory Wells	0	0	0	0	0.00	0.00	0.00	0.00
Empl.									
	Development Wells	18	6	8	4	.48	.12	.30	.06
	Total	18	6	8	4	.48	.12	.30	.06
1987[1]									
	Exploratory Wells	0	0	0	0	0.00	0.00	0.00	0.00
Empl.									
	Development Wells	21	12	5	4	1.17	.74	.25	.18
	Total	21	12	5	4	1.17	.74	.25	.18
1988[1]									
	Exploratory Wells	0	0	0	0	0	0	0	0
Empl.									
	Development Wells	29	15	9	5	1.55	1.03	.28	.24
	Total	29	15	9	5	1.55	1.03	.28	.24
1989[1]									
	Exploratory Wells								
Empl.									
	Development Wells	32	7	14	11	1.48	.59	.36	.53
	Total	32	7	14	11	1.48	.59	.36	.53
1990[1]									
	Exploratory Wells	5	0	2	3	.122	0	.01	.11
Empl.									
	Development Wells	34	11	14	9	1.65	.83	.35	.46
	Total	39	11	16	12	1.78	.83	.36	.57
1991[2]									
	Exploratory Wells	4	0	0	4	.08	0	0	.08
Empl.									
	Development Wells	28	10	9	9	1.59	.86	.39	.34
	Total	32	10	9	13	1.67	.86	.39	.42
1992[2]									
	Exploratory Wells	0	0	0	0	0	0	0	0
Empl.									
	Development Wells	18	1	11	6	.29	.05	.17	.07
	Total	18	1	11	6	.29	.05	.17	.07
1993[2]									
	Exploratory Wells	0	0	0	0	0	0	0	0
Empl.									
	Development Wells	16	9	6	1	.63	.45	.17	.01
	Total	16	9	6	1	.63	.45	.17	.01

1994[2]									
	Exploratory Wells	3	0	1	2	.09	0	.05	.04
Empl.									
	Development Wells	57	5	40	12	1.29	.24	.70	.35
	Total	60	5	41	14	1.38	.24	.75	.39
1995[2]									
	Exploratory Wells	0	0	0	0	0	0	0	0
Empl.									
	Development Wells	45	15	24	6	.74	.23	.40	.11
	Total	45	15	24	6	.74	.23	.40	.11
1996[2]									
	Exploratory Wells	0	0	0	0	0	0	0	0
Empl.									
	Development Wells	53	7	38	8	1.24	.27	.76	.21
	Total	53	7	38	8	1.24	.27	.76	.21

Programs		Gross Wells Total	Gross Wells Oil	Gross Wells Gas	Gross Wells Dry	Net Wells Total	Net Wells Oil	Net Wells Gas	Net Wells Dry
1997(2)									
	Exploratory Wells	2	0	0	2	.10	0	0	.10
Empl.									
	Development Wells	80	8	58	14	1.80	.22	1.16	.42
	Total	82	8	58	16	1.90	.22	1.16	.52
1998(2)									
	Exploratory Wells	2	0	1	1	.03	0	.02	.01
Empl.									
	Development Wells	76	3	52	21	1.51	.02	.94	.56
	Total	78	3	53	22	1.54	.02	.96	.57
1999(2)									
	Exploratory Wells	0	0	0	0	0	0	0	0
Empl.									
	Development Wells	51	1	42	8	1.09	.02	.87	.20
	Total	51	1	42	8	1.09	.02	.87	.20
2000									
	Exploratory Wells	2	0	2	0	.09	0	.09	0
Empl.									
	Development Wells	98	7	73	18	1.92	.07	1.43	.42
	Total	100	7	75	18	2.01	.07	1.52	.42
2001									
	Exploratory Wells	3	0	0	3	.05	0	0	.05
Empl.									
	Development Wells	123	7	94	22	1.25	.03	.85	.37
	Total	126	7	94	25	1.30	.03	.85	.42
2002									
	Exploratory Wells	6	0	2	4	.03	0	.02	.01
Empl.									
	Development Wells	91	4	63	24	1.18	.05	.74	.39
	Total	97	4	65	28	1.21	.05	.76	.40
2003									
	Exploratory Wells	4	1	3	0	.03	.01	.02	0
Empl.									
	Development Wells	145	5	119	21	.59	.02	.44	.13
	Total	149	6	122	21	.62	.03	.46	.13
2004									
	Exploratory Wells	14	1	7	6	.06	.01	.03	.03
Empl.									
	Development Wells	156	18	114	24	.65	.07	.45	.12
	Total	170	19	121	30	.71	.08	.48	.15
2005									
	Exploratory Wells	8	1	5	2	.04	0	.02	.02
Empl.									
	Development Wells	184	17	154	13	.68	.05	.57	.06
	Total	192	18	159	15	.72	.05	.59	.08
Period of January 1, 2005 To September 30, 2005									
2006									
	Exploratory Wells	8	0	4	4	.04	0	.03	.01
Empl.									
	Development Wells	170	9	142	19	.58	.02	.49	.08
	Total	178	9	146	23	.62	.02	.52	.09

(1) Effective December 31, 1993 this Program was merged with and into the Consolidated Program.

(2) Effective December 31, 2002 this Program was merged with and into the Consolidated Program.

GENERAL PARTNERS' PAYOUT TABLE[1]

As of September 30, 2006

Program	Total Expenditures Including Operating Costs[2]	Total Revenues Before Deducting Operating Costs	Total Revenues Before Deducting Operating Costs for 3 Months Ended September 30, 2006
1979[***]	$ 8,781,728	$10,846,983	—
1980	4,043,599	4,044,424	—
1981	8,325,594	6,338,173	—
1981-II	6,642,875	3,995,616	—
1982-A	9,190,842	6,782,893	—
1982-B	4,213,710	3,126,326	—
1983-A	2,277,514	1,312,531	—
1984	2,860,558	2,741,108	44,856
1984 Employee[*]	1,542	1,745	—
1985 Employee[*]	2,820	1,808	—
1986 Energy Income Fund[**]	2,389,019	2,158,326	24,575
1986 Employee[*]	4,403	6,813	—
1987 Employee[*]	624,354	815,358	—
1988 Employee[*]	1,196,564	1,588,132	—
1989 Employee[*]	1,424,525	1,171,961	—
1990 Employee[*]	653,563	525,572	—
1991 Employee[****]	2,352,323	3,046,177	—
1992 Employee[****]	241,577	400,556	—
1993 Employee[****]	496,051	717,460	—
1994 Employee[****]	1,435,412	1,841,119	—
1995 Employee[****]	476,082	599,485	—
1996 Employee[****]	901,692	869,473	—
1997 Employee[****]	1,296,424	1,165,747	—

1998 Employee(****)	1,180,292	1,083,527	—
1999 Employee(****)	953,718	1,314,469	—
Consolidated Program	12,212	52,024	2,066
2000 Employee	2,193,356	3,048,301	69,076
2001 Employee	1,060,558	1,029,649	28,804
2002 Employee	1,120,613	1,248,559	50,027
2003 Employee	2,039,165	2,861,351	177,450
2004 Employee	679,929	664,308	41,950
2005 Employee	2,160,105	1,077,798	211,774
2006 Employee	1,946,520	143,923	124,242

(*) Effective December 31, 1993, this program was merged with and into the Consolidated Program.

(**) Formed primarily for purposes of acquiring producing oil and gas properties.

(***) Effective July 1, 2003 this program was dissolved.

(****) Effective December 31, 2002 this Program was merged with and into the Consolidated Program.

LIMITED PARTNERS' PAYOUT TABLE(1)

As of September 30, 2006

Program	Total Expenditures Including Operating Costs(2)	Total Revenues Before Deducting Operating Costs	Total Revenues Before Deducting Operating Costs for 3 Months Ended September 30, 2006
1979(***)	$14,729,990	$18,839,040	—
1980	17,688,367	6,949,008	—
1981	37,073,946	15,768,826	—
1981-II	18,638,600	7,028,946	—
1982-A	24,866,078	12,708,949	—
1982-B	12,069,566	5,367,312	—
1983-A	3,770,856	1,922,177	—
1984	3,298,249	2,835,711	44,856
1984 Employee(*)	120,942	171,540	—
1985 Employee(*)	277,901	178,984	—
1986 Energy Income Fund(**)	3,042,353	4,357,691	36,862
1986 Employee(*)	435,858	676,972	—
1987 Employee(*)	341,846	469,830	—
1988 Employee(*)	333,898	446,044	—
1989 Employee(*)	179,593	175,331	—
1990 Employee(*)	300,852	188,848	—
1991 Employee(****)	620,136	811,871	—
1992 Employee(****)	622,697	1,033,805	—
1993 Employee(****)	451,551	664,349	—
1994 Employee(****)	582,274	754,012	—
1995 Employee(****)	762,211	941,188	—
1996 Employee(****)	549,125	534,519	—
1997 Employee(****)	605,116	524,732	—

1998 Employee(****)	613,890	551,342	—
1999 Employee(****)	289,622	392,633	—
Consolidated Program	1,121,421	5,148,663	205,209
2000 Employee	302,346	415,796	9,420
2001 Employee	475,922	462,596	12,941
2002 Employee	576,430	643,197	25,772
2003 Employee	416,522	585,776	36,345
2004 Employee	555,970	543,528	34,324
2005 Employee	534,957	252,818	49,675
2006 Employee	877,246	64,661	55,819

(*) Effective December 31, 1993, this program was merged with and into the Consolidated Program.

(**) Formed primarily for purposes of acquiring producing oil and gas properties.

(***) Effective July 1, 2003, this program was dissolved.

(****) Effective December 31, 2002 this Program was merged with and into the Consolidated Program.

GENERAL PARTNERS' NET CASH TABLE (1)

As of September 30, 2006

Program	Total Expenditures Less Operating Costs(2)	Total Revenues Less Operating Costs	Total Revenues Less Operating Costs for 3 Months Ended Sept. 30, 2006	Total Revenues Distributed	Total Revenues Distributed for 3 Months Ended Sept. 30, 2006
1979(***)	$ 2,805,917	$4,871,172	$ —	$3,961,014	$ —
1980	2,628,978	2,629,803	—	2,635,751	—
1981	6,546,160	4,558,739	—	5,368,272	—
1981-II	4,817,145	2,169,886	—	2,609,000	—
1982-A	6,297,972	3,890,023	—	3,755,000	—
1982-B	2,565,504	1,478,120	—	1,158,000	—
1983-A	1,380,331	415,348	—	819,000	—
1984	945,964	826,514	(2,005)	1,159,584	4,500
1984 Employee(*)	874	1,077	—	1,000	—
1985 Employee(*)	2,300	1,288	—	1,035	—
1986 Energy Income Fund(**)	200,342	(30,351)	(34,164)	473,865	—
1986 Employee(*)	2,698	5,108		4,486	—
1987 Employee(*)	357,368	548,372	—	465,800	—
1988 Employee(*)	770,272	1,161,840	—	942,800	—
1989 Employee(*)	1,010,133	752,569	—	607,900	—
1990 Employee(*)	466,272	338,281	—	266,600	—
1991 Employee(****)	1,056,956	1,750,810	—	1,618,020	—
1992 Employee(****)	99,250	258,229	—	230,839	—
1993 Employee(****)	311,650	533,059	—	472,480	—
1994 Employee(****)	856,390	1,262,097	—	1,076,708	—
1995 Employee(****)	330,617	454,020	—	350,504	—
1996 Employee(****)	681,656	649,437	—	450,383	—

1997 Employee(****)	1,057,002	926,325	—	695,477	—
1998 Employee(****)	920,862	824,096	—	638,218	—
1999 Employee(****)	706,281	1,067,032	—	796,578	—
Consolidated Program	12,484	33,724	1,101	32,047	1,000
2000 Employee	1,590,514	2,445,459	49,937	1,704,669	45,000
2001 Employee	870,158	734,334	20,017	618,000	20,000
2002 Employee	919,143	843,274	38,788	714,000	20,250
2003 Employee	1,535,633	1,650,745	137,249	1,775,750	160,000
2004 Employee	574,389	318,148	30,945	364,500	32,000
2005 Employee	1,990,946	52,301	165,623	197,000	145,000
2006 Employee	1,918,515	—	105,811	—	—

(*) Effective December 31, 1993, this program was merged with and into the Consolidated Program.

(**) Formed primarily for purposes of acquiring producing oil and gas properties.

(***) Effective July 1, 2003, this program was dissolved.

(****) Effective December 31, 2002 this Program was merged with and into the Consolidated Program.

LIMITED PARTNERS' NET CASH TABLE(1)

As of September 30, 2006

Program	Capital Contributed	Total Expenditures Less Operating Costs(2)	Total Revenues Less Operating Costs	Total Revenues Less Operating Costs for 3 Months Ended Sept. 30, 2006	Total Revenues Distributed	Total Revenues Distributed for 3 Months Ended Sept. 30, 2006
1979(***)	$ 3,000,000	$ 6,085,402	$10,194,451	$ —	$ 6,198,801	$ —
1980	12,000,000(3)	14,469,265	3,729,906	—	760,000	—
1981	29,255,000(4)	32,700,741	11,395,621	—	5,335,065	—
1981-II	15,000,000	16,603,760	4,994,106	—	1,710,001	—
1982-A	21,140,000	21,591,442	9,434,313	—	6,342,000	—
1982-B	10,555,000	9,935,850	3,233,596	—	2,828,740	—
1983-A	2,530,000	2,993,705	1,145,026	—	227,700	—
1984	1,875,000	2,035,143	1,450,772	23,360	1,247,756	23,940(5)
1984 Employee(*)	174,000	86,664	137,262	—	125,280	—
1985 Employee(*)	283,500	227,670	128,753	—	182,644	—
1986 Energy Income Fund(**)	1,000,000	1,023,012	2,219,611	12,246	2,141,900	-(6)
1986 Employee(*)	229,750	267,008	508,122	—	460,007	—
1987 Employee(*)	209,000	207,060	335,044	—	324,845	—
1988 Employee(*)	177,000	214,712	326,858	—	281,630	—
1989 Employee(*)	157,000	157,306	153,044	—	147,737	—
1990 Employee(*)	253,000	254,483	142,479	—	180,895	—
1991 Employee(****)	263,000	275,590	467,325	—	438,947	—
1992 Employee(****)	240,000	256,030	667,138	—	626,888	—
1993 Employee(****)	245,000	281,201	493,998	—	459,375	—
1994 Employee(****)	284,000	345,243	516,980	—	433,668	—
1995 Employee(****)	454,000	493,337	672,314	—	572,524	—
1996 Employee(****)	437,000	419,615	405,010	—	382,812	—

1997 Employee(****)	413,000	495,786	415,402	—	348,159	—
1998 Employee(****)	471,000	486,317	423,769	—	398,937	—
1999 Employee(****)	141,000	214,376	317,387	—	288,204	—
Consolidated	—	1,148,330	3,321,299	107,438	3,264,4140	114,836(7)
2000 Employee	199,000	217,240	330,690	6,816	298,953	3,383(8)
2001 Employee	370,000	390,941	377,615	8,994	317,928	9,620(9)
2002 Employee	457,000	473,497	540,265	19,984	462,056	12,796(10)
2003 Employee	284,000	314,529	483,783	28,112	412,144	34,364(11)
2004 Employee	434,000	469,953	457,512	25,322	374,108	28,644(12)
2005 Employee	496,000	495,999	213,860	38,961	204,352	53,568(13)
2006 Employee	767,000	861,942	49,357	46,792	—	—

(*) Effective December 31, 1993, this program was merged with and into the Consolidated Program.

(**) Formed primarily for purposes of acquiring producing oil and gas properties.

(***) Effective July 1, 2003, this program was dissolved.

(****) Effective December 31, 2002 this Program was merged with and into the Consolidated Program.

(1) Amounts reflect the accrual method of accounting.

(2) Does not include expenditures of $237,600, $920,453, $2,252,900, $1,480,248, $2,079,268, $985,371 and $241,076 which were obtained from bank borrowings and used to pay the limited partners' share of sales commissions of $237,600, $722,453, $1,940,400, $1,183,248, $1,656,468, $827,046 and $190,476 and organization costs of $—0—, $198,000, $312,500, $297,000, $422,800, $158,325 and $50,600 for the 1979, 1980, 1981, 1981-II, 1982-A, 1982-B and 1983-A Programs, respectively.

(3) Includes original subscriptions of limited partners totaling $10,000,000 and additional assessments totaling $2,000,000.

(4) Includes original subscriptions of limited partners totaling $25,000,000 and additional assessments totaling $4,255,000.

(5) In November 2006 the 1984 Program made a distribution of $31,185 to that program's limited partners.

(6) In November 2006 the 1986 Program made a distribution of $18,000 to that program's limited partners.

(7) In November 2006 the Consolidated Employee Program made a distribution of $101,038 to that program's limited partners.

(8) In November 2006 the 2000 Employee Program made a distribution of $7,761 to that program's limited partners.

(9) In November 2006 the 2001 Employee Program made a distribution of $9,250 to that program's limited partners.

(10) In November 2006 the 2002 Employee Program made a distribution of $18,737 to that program's limited partners.

(11) In November 2006 the 2003 Employee Program made a distribution of $30,388 to that program's limited partners.

(12) In November 2006 the 2004 Employee Program made a distribution of $31,682 to that program's limited partners.

(13) In November 2006 the 2005 Employee Program made a distribution of $42,656 to that program's limited partners.

FEDERAL INCOME TAX CONSIDERATIONS

The following is a summary of the opinions of Conner & Winters on all material federal income tax consequences to the Partnership and to the Limited Partners. The full tax opinion of Conner & Winters is attached to this Memorandum as Exhibit B. All prospective investors should review Exhibit B in its entirety before investing in the Partnership. There may be aspects of a particular investor's tax situation which are not addressed in the following discussion or in Exhibit B. Additionally, the resolution of certain tax issues depends on future facts and circumstances not known to Conner & Winters as of the date of this Memorandum; thus, no assurance as to the final resolution of such issues should be drawn from the following discussion.

The following statements are based on the provisions of the Code, existing and proposed regulations promulgated under the Code ("Regulations"), current administrative rulings, and court decisions. It is possible that legislative or administrative changes or future court decisions may significantly modify the statements and opinions expressed herein. Such changes could be retroactive with respect to transactions occurring prior to the date of such changes.

Moreover, uncertainty exists concerning some of the federal income tax aspects of the transactions being undertaken by the Partnership. Some of the tax positions being taken by the Partnership may be challenged by the Service. Thus, there can be no assurance that all of the anticipated tax benefits of an investment in the Partnership will be realized.

Conner & Winters' opinion is based on the transactions described in this Memorandum (the **"Transaction"**) and on facts as they have been represented to Conner & Winters or determined by it as of the date of the opinion. Any alteration of the facts could render the conclusions in the opinion inapplicable.

Because of the factual nature of the inquiry, and in certain cases the lack of clear authority in the law, it is not possible to reach a judgment as to the outcome on the merits (either favorable or unfavorable) of certain material federal income tax issues as described more fully herein.

Summary of Conclusions

Opinions expressed: The following is a summary of the specific federal income tax opinions rendered by Conner & Winters in Exhibit B.

1. The material federal income tax benefits in the aggregate from an investment in the Partnership will be realized.

2. The Partnership will be treated as a partnership for federal income tax purposes and not as a corporation, an association taxable as a corporation or a "publicly traded partnership". See "Partnership Status"; "Federal Taxation of Partnerships."

3. To the extent the Partnership's wells are timely drilled and its drilling costs are timely paid, the Partners will be entitled to their pro rata shares of the Partnership's intangible drilling and development costs ("IDC") paid in 2007. See "Intangible Drilling and Development Costs Deductions."

4. Most Limited Partners' Units will be considered as ownership interests in a passive activity within the meaning of Code Section 469 and losses generated therefrom will be limited by the passive activity provisions of the Code. See "Passive Loss and Credit Limitations."

5. To the extent provided in such opinion, the Partners' distributive shares of Partnership tax items will be determined and allocated substantially in accordance with the terms of the Partnership Agreement. See "Partnership Allocations."

6. The Partnership will not be required to register with the Service as a tax shelter. See "Registration as a Tax Shelter."

No opinion expressed: Due to the lack of authority regarding, or the essentially factual nature of, the issue, Conner & Winters expresses no opinion as to:

1. The impact of an investment in the Partnership on an investor's alternative minimum tax liability;

2. Whether each Partner will be entitled to percentage depletion since such a determination is dependent on the status of the Partner as an independent producer and on the Partner's other oil and gas production (See "Depletion Deductions");

3. Whether the Partnership will be treated as the tax owner of Partnership Properties acquired by the General Partner as nominee for the Partnership.

Facts and Representations: In rendering its opinion, Conner & Winters relied on certain representations made to it by the General Partner, including the following:

1. The Partnership Agreement to be entered into by and among the General Partner and Limited Partners and any amendments thereto will be duly executed and will be made available to any Limited Partner on written request. A certificate of limited partnership will be duly recorded in all places required under the Oklahoma Revised Uniform Limited Partnership Act (the **"Act"**) for the due formation of the Partnership and for the continuation thereof in accordance with the terms of the Partnership Agreement. The Partnership will at all times be operated in accordance with the terms of the Partnership Agreement, this Memorandum, and the Act.

2. No election will be made by the Partnership, Limited Partners, or General Partner to be excluded from the application of the provisions of Subchapter K of the Code.

3. The Partnership will own operating mineral interests, as defined in the Code and in the Regulations, and none of the Partnership's revenues will be from non-working interests.

4. The General Partner will cause the Partnership to elect properly to deduct currently all IDC.

5. The Partnership will have a December 31 taxable year and will report its income on the accrual basis.

6. All Partnership wells will be spudded no later than December 31, 2007. The entire amount to be paid under any drilling and operating agreements entered into by the Partnership will be attributable to IDC.

7. Such drilling and operating agreements will be duly executed and will govern the operation of the Partnership's wells.

8. Based on the General Partner's review of its experience with its previous oil and gas partnerships for the past several years and on the intended operations of the Partnership, the General Partner believes that the sum of (i) the aggregate deductions, including depletion deductions, and (ii) 350 percent of the aggregate tax credits from the Partnership will not, as of the close of any of the first five years ending after the date on which Units are offered for sale, exceed two times the aggregate cash invested by the Partners in the Partnership as of such dates. In that regard, the General Partner has reviewed the economics of its similar oil and gas partnerships for the past several years, and has represented that it has determined that none of those partnerships has resulted in a "tax shelter ratio", as such term is defined in the Code and Regulations, greater than two to one. Further, the General Partner has represented that the deductions that are or will be represented as potentially allowable to an investor will not result in the Partnership having a tax shelter ratio, as such term is defined in the Code and Regulations, greater than two to one.

9. The General Partner believes that at least 90% of the gross income of the Partnership will constitute income derived from the exploration, development, production, and/or marketing of oil and gas. The General Partner does not believe that any market will ever exist for the sale of Units and the General Partner will not make a market for the Units. Further, the Units will not be traded on an established securities market.

10. The Partnership and each Partner will have the objective of carrying on the business of the Partnership for profit and dividing the gain therefrom.

11. The General Partner will, as nominee for the Partnership, acquire and hold title to Partnership Properties on behalf of the Partnership; the General Partner will enter into an agency agreement before the General Partner acquires any such oil and gas properties on behalf of the Partnership; the agency agreement will reflect that the General Partner's acquisition of Partnership properties is on behalf of the Partnership; and the General Partner will execute assignments of all oil and gas interests acquired by it on behalf of the Partnership to the Partnership.

The opinions of Conner & Winters are also subject to all the assumptions, qualifications, and limitations set forth in the following discussion and in the opinion, including the assumptions that each of the Partners has full power, authority, and legal right to enter into and perform the terms of the Partnership Agreement and to take any and all actions thereunder in connection with the transactions contemplated thereby.

Each prospective investor should be aware that, unlike a ruling from the Service, an opinion of Conner & Winters represents only Conner & Winters' best judgment. **THERE CAN BE NO ASSURANCE THAT THE SERVICE WILL NOT SUCCESSFULLY ASSERT POSITIONS WHICH ARE INCONSISTENT WITH THE OPINIONS OF CONNER & WINTERS SET FORTH IN THIS DISCUSSION AND EXHIBIT B OR IN THE TAX REPORTING POSITIONS TAKEN BY THE PARTNERS OR THE PARTNERSHIP. EACH PROSPECTIVE INVESTOR SHOULD CONSULT HIS OR HER OWN TAX ADVISOR TO DETERMINE THE EFFECT OF THE TAX ISSUES DISCUSSED HEREIN AND IN EXHIBIT B ON HIS OR HER INDIVIDUAL TAX SITUATION.**

Compliance with Circular 230: The United States Treasury Department establishes standards for tax practitioners who practice before the Internal Revenue Service (the "Service"). Those standards are set forth in a publication known as Circular 230. Circular 230 was recently revised and now requires that written statements issued by a tax practitioner that constitute "Covered Opinions" contain certain material and conform to a specific manner of presentation. Additionally, Circular 230 now requires that other written advice issued by a tax practitioner that does not constitute a Covered Opinion satisfy certain "reasonableness" standards with respect to representations and factual and legal assumptions. Neither this summary discussion nor the tax opinion of Conner & Winters attached to the Memorandum as Exhibit B constitutes a Covered Opinion within the meaning of

Circular 230. This summary discussion is drafted in a manner designed to comply with the requirements of Circular 230 with respect to the reasonableness standards for other written advice.

IMPORTANT LIMITATIONS ON SUMMARY AND TAX OPINION

Neither this summary discussion nor the tax opinion of Conner & Winters attached to the Memorandum as Exhibit B was intended or written to be used, and neither may be used, for the purpose of avoiding penalties that may be imposed by the Service. This summary discussion and the tax opinion of Conner & Winters were written to support the promotion or marketing of Units in the Partnership. Prospective investors should seek advice based on their particular circumstances from an independent tax advisor.

General Tax Effects of Partnership Structure

The Partnership will be formed as a limited partnership pursuant to the Partnership Agreement and the laws of the State of Oklahoma. **No tax ruling will be sought from the Service as to the status of the Partnership as a partnership for federal income tax purposes.** The applicability of the federal income tax consequences described herein depends on the treatment of the Partnership as a partnership for federal income tax purposes and not as a corporation and not as an association taxable as a corporation. Any tax benefits anticipated from an investment in the Partnership would be adversely affected or eliminated if the Partnership were treated as a corporation for federal income tax purposes.

Conner & Winters is of the opinion that, at the time of its formation, the Partnership will be treated as a partnership for federal income tax purposes. The opinion is based on the provisions of the Partnership Agreement, applicable state and federal law and representations made by the General Partner

Under the Code, a partnership is not a taxable entity and, accordingly, incurs no federal income tax liability. Rather, a partnership is a “pass-through” entity which is required to file an information income tax return with the Service. In general, the character of a partner’s share of each item of income, gain, loss, deduction, and credit is determined at the partnership level. Each partner is allocated a distributive share of such items in accordance with the partnership agreement and is required to take such items into account in determining the partner’s income. Each partner includes such amounts in determining his or her income for any taxable year of the partnership ending within or with the taxable year of the partner, without regard to whether the partner has received or will receive any cash distributions from the partnership.

Ownership of Partnership Properties

The General Partner has indicated that it, as nominee for the Partnership (the **“Nominee”**), will acquire and hold title to Partnership Properties on behalf of the Partnership. The Nominee and the Partnership will enter into an agency agreement before the Nominee acquires any oil and gas properties on behalf of the Partnership. That agency agreement will reflect that the Nominee’s acquisition of Partnership Properties is on behalf of the Partnership. The Nominee will execute assignments of all oil and gas interest acquired by the Nominee on behalf of the Partnership to the Partnership. For various cost and procedural reasons, the assignments will not be recorded in the real estate records in the counties in which the Partnership Properties are located. That is, while the Partnership will be the owner of the Partnership Properties, there will be no public record of that ownership. It is possible that the Service could assert that the Nominee should be treated for federal income tax purposes as the owner of the Partnership Properties, notwithstanding the assignment of those Partnership Properties to the Partnership. If the Service were to argue successfully that the Nominee should be treated as the tax owner of the Partnership Properties, there would be significant adverse federal income tax consequences to the Limited Partners, such as the unavailability of depletion deductions in respect of income from Partnership Properties. The Service is concerned that taxpayers not shift the tax consequences of transactions between parties based on the parties’ declaration that one party is the agent of another; the Service generally requires that taxpayers respect the form of their transactions and ownership of property. Based on this concern, the Service may challenge the Partnership’s treatment of Partnership Properties, and tax attributes thereof, which are held of record by the Nominee.

In *Commissioner of Internal Revenue v. Bollinger*, 485 U.S. 340 (1988), the United States Supreme Court reviewed a principal-agent relationship and held for the taxpayer in concluding that the principal should be treated as the tax owner of property held in the name of the agent. In that case the Supreme Court noted that "It seems to us that the genuineness of the agency relationship is adequately assured, and tax-avoiding manipulation adequately avoided, when the fact that the corporation is acting as agent for its shareholders with respect to a particular asset is set forth in a written agreement at the time the asset is acquired, the corporation functions as agent and not principal with respect to the asset for all purposes, and the corporation is held out as the agent and not principal in all dealings with third parties relating to the asset." While the Partnership and the Nominee will have in place an agreement defining their relationship before any Partnership Properties are acquired by the Nominee and the Nominee will function as agent with respect to those Partnership Properties on behalf of the Partnership, the Nominee will not hold itself out to all third parties as the agent of the Partnership in dealings relating to the Partnership Properties. Unlike the relationship between the principal and the agent in *Bollinger*, the Nominee will, however, assign title to Partnership Properties to the Partnership, but will not record those assignments. Accordingly, the facts related to the relationship between the Nominee and the Partnership are not the same as the facts in *Bollinger* and it is not clear that the failure of the Nominee to hold itself out to third parties as the agent of the Partnership in dealings relating to Partnership Properties should result in the treatment of the Nominee as the tax owner of the Partnership Properties. For the foregoing reasons, Conner & Winters has not expressed an opinion on this issue, but Conner & Winters believes that substantial arguments may be made that the Partnership should be treated as the tax owner of Partnership Properties acquired by the Nominee on the Partnership's behalf. If the Partnership were not treated as the tax owner of Partnership Properties, then the following discussions which relate to the Partners' deduction of tax items which are derived from Partnership Properties, such as IDC, depletion and depreciation, would not be applicable.

Intangible Drilling and Development Costs Deductions

Congress granted to the Secretary of the Treasury the authority to prescribe regulations that would allow taxpayers the option of deducting, rather than capitalizing, IDC. The Secretary's rules state that, in general, the option to deduct IDC applies only to expenditures for drilling and development items that do not have a salvage value.

The Memorandum provides that 75% of the Partners' capital contributions will be utilized for IDC, which will flow through to the Partners as a deductible item in the year of investment. The deduction of IDC by most Limited Partners generally will be available only to offset passive income. Based on a deduction of 75% of a Partner's capital contribution, a one Unit ($1,000) investor in a 35% marginal Federal tax bracket could possibly reduce taxes payable by $262. The investor might also realize additional tax savings on income taxes in the state in which such investor resides.

Classification of Costs. In general, IDC consists of those costs which in and of themselves have no salvage value. In previous partnerships for which the General Partner has served as general partner, intangible drilling and development costs have ranged from 72% to 27% of the investors' contributions. While the planned activities of the Partnership are similar in nature to those of prior partnerships, the amount of expenditures classified as IDC could be greater or less than for prior partnerships. In addition, a partnership's classification of a cost as IDC is not binding on the Service, which might reclassify an item labeled as IDC as a cost which must be capitalized. To the extent not deductible, such amounts will be included in the Partnership's basis in a mineral property and in the Partners' tax basis in their interests in the Partnership.

Timing of Deductions. Although the Partnership will elect to deduct IDC, each investor has an option of deducting IDC, or capitalizing all or a part of the IDC and amortizing it on a straight-line basis over a sixty-month period, beginning with the taxable month in which the expenditure is made. In addition to the effect of this change on regular taxable income, the two methods have different treatment under the Alternative Minimum Tax.

Although the General Partner will attempt to satisfy each requirement for deductibility of the Partnership's IDC in 2007, no assurance can be given that the Service will not successfully contend that the IDC of a Partnership well which is not completed until 2008 is not deductible in whole or in part until 2008. Furthermore, no assurance can be given that the Service will not challenge the current deduction of IDC because of the prepayment being made to a related party. If the Service were successful with such a challenge, some portion of the Partners' deductions for IDC would be deferred to later years.

Recapture of IDC. IDC previously deducted that is allocable to a property (directly or through the ownership of an interest in a partnership) and which, if capitalized, would have been included in the adjusted basis of the property is recaptured as ordinary income to the extent of any gain realized on the disposition of the property. Treasury regulations provide that recapture is determined at the partner level (subject to certain anti-abuse provisions). Where only a portion of recapture property is disposed of, any IDC related to the entire property is recaptured to the extent of the gain realized on the portion of the property sold. In the case of the disposition of an undivided interest in a property (as opposed to the disposition of a portion of the property), a proportionate part of the IDC with respect to the property is treated as allocable to the transferred undivided interest to the extent of any realized gain.

Depletion Deductions

The owner of an economic interest in an oil and gas property is entitled to claim the greater of percentage depletion or cost depletion with respect to oil and gas properties which qualify for such depletion methods. In the case of partnerships, the depletion allowance must be computed separately by each partner and not by the partnership. For properties placed in service after 1986, depletion deductions, to the extent they reduce basis in an oil and gas property, are subject to recapture under Code section 1254.

Cost depletion for any year is determined by multiplying the number of units (e.g., barrels of oil or Mcf of gas) sold during the year by a fraction, the numerator of which is the cost or other basis of the mineral interest and the denominator of which is total reserves available at the beginning of the period. In no event can the cost depletion exceed the adjusted basis of the property to which it relates.

Percentage depletion is a statutory allowance pursuant to which a deduction currently equal to 15% of the taxpayer’s gross income from each property is allowed in any taxable year, not to exceed 100% of the taxpayer’s taxable income from the property (computed without the allowance for depletion) with the aggregate deduction limited to 65% of the taxpayer’s taxable income for the year (computed without regard to percentage depletion and net operating loss and capital loss carrybacks). The percentage depletion deduction rate will vary with the price of oil, but the rate will not be less than 15%. A percentage depletion deduction that is disallowed in a year due to the 65% of taxable income limitation may be carried forward and allowed as a deduction for a subsequent year, subject to the 65% limitation in that subsequent year. Percentage depletion deductions reduce the taxpayer’s adjusted basis in the property. However, unlike cost depletion, percentage depletion deductions are not limited to the adjusted basis of the property; the percentage depletion amount continues to be allowable as a deduction after the adjusted basis has been reduced to zero.

The availability of depletion, whether cost or percentage, will be determined separately by each Partner. Each Partner must separately keep records of his share of the adjusted basis in an oil or gas property, adjust such share of the adjusted basis for any depletion taken on such property, and use such adjusted basis each year in the computation of his cost depletion or in the computation of his gain or loss on the disposition of such property. These requirements may place an administrative burden on a Partner.

Production Activities Deduction

The Partnership will be eligible for the deduction available for qualified production activities. The deduction will be applied at the Partner (as a deduction from adjusted gross income for an individual) level based on allocations to Partners of their shares of the Partnership’s qualified production activities income. Qualified production activities income for the Partnership will include its oil and gas production gross receipts reduced by the sum of the cost of goods sold allocable to such receipts, other deductions, expenses and losses directly allocable to such receipts, and a ratable portion of other deductions and expenses not directly allocable to such receipts or any other class of income of the Partnership. For taxable years beginning in 2007, 2008 or 2009, the deduction rate is 6 percent and for taxable years beginning after 2009, the deduction rate is 9 percent. The amount of the deduction allowable for any taxable year may not exceed 50 percent of the W-2 wages of the taxpayer for the year (in the case of a Partner, the Partner’s allocable share of the Partnership’s W-2 wages).

Depreciation Deductions

The Partnership will claim depreciation, cost recovery, and amortization deductions with respect to its basis in Partnership Property as permitted by the Code.

Transaction Fees

The Partnership may classify a portion of the fees or expense reimbursements to be paid to third parties and to the General Partner as expenses which are deductible as organizational expenses or otherwise. There is no assurance that the Service will allow the deductibility of such expenses and Conner & Winters expresses no opinion with respect to the allocation of such fees or reimbursements to deductible and nondeductible items.

Generally, expenditures made in connection with the creation of, and with sales of interests in, a partnership will fit within one of several categories.

A partnership may elect to amortize and deduct its organizational expenses ratably over a period of not less than 60 months commencing with the month the partnership begins business. Examples of organizational expenses are legal fees for services incident to the organization of the partnership, such as negotiation and preparation of a partnership agreement, accounting fees for services incident to the organization of the partnership, and filing fees.

No deduction is allowable for “syndication expenses,” examples of which include brokerage fees, registration fees, legal fees of the underwriter or placement agent and the issuer (general partners or the partnership) for securities advice and for advice pertaining to the adequacy of tax disclosures in the offering or private placement memorandum for securities law purposes, printing costs, and other selling or promotional material. These costs must be capitalized. Payments for services performed in connection with the acquisition of capital assets must be amortized over the useful life of such assets.

No deduction is allowable with respect to “start-up expenditures,” although such expenditures may be capitalized and amortized over a period of not less than 60 months.

The Partnership intends to make overhead reimbursement payments to the General Partner, as described in greater detail in the Memorandum. To be deductible, payments to a partner must be for services rendered by the partner other than in his or its capacity as a partner or for compensation determined without regard to partnership income. Payments which are not deductible because they fail to meet this test may be treated as special allocations of income to the recipient partner and thereby decrease the net loss, or increase the net income among all partners. If the Service were to successfully challenge the General Partner’s allocations, a Partner’s taxable income could be increased, thereby resulting in increased taxes and in potential liability for interest and penalties.

Basis and At Risk Limitations

A Partner’s share of Partnership losses will be allowed as a deduction by the Partner only to the extent of the aggregate amount with respect to which the taxpayer-Partner is “at risk” for the Partnership’s activity at the close of the taxable year. Any such loss disallowed by the “at risk” limitation shall be treated as a deduction allocable to the activity in the first succeeding taxable year.

The Code provides that a taxpayer must recognize taxable income to the extent that his or her “at risk” amount is reduced below zero. This “recaptured” income is limited to the sum of the loss deductions previously allowed to the taxpayer, less any amounts previously recaptured. A taxpayer may be allowed a deduction for the recaptured amounts included in his taxable income if and when he increases his amount “at risk” in a subsequent taxable year.

The Limited Partners will purchase Units by tendering cash to the Partnership. To the extent the cash contributed constitutes the “personal funds” of the Partners, the Partners should be considered at risk with respect to those amounts. If the cash contributed constitutes “personal funds,” in the opinion of Conner & Winters, neither the at risk rules nor the adjusted basis rules will limit the deductibility of losses generated from the Partnership and allocated to a Limited Partner, to the extent of such Limited Partner’s cash contributions. In no event, however, may a Partner deduct his distributive share of partnership loss where such share exceeds the Partner’s tax basis in the Partnership.

Passive Loss Limitations

Introduction. The deductibility of losses generated from passive activities will be limited for certain taxpayers. The passive activity loss limitations apply to individuals, estates, trusts, and personal service corporations as well as, to a lesser extent, closely held C corporations.

The definition of a "passive activity" generally encompasses all rental activities as well as all activities with respect to which the taxpayer does not "materially participate." A taxpayer will be considered as materially participating in a venture only if the taxpayer is involved in the operations of the activity on a "regular, continuous, and substantial" basis. In addition, no limited partnership interest will be treated as an interest with respect to which a taxpayer materially participates.

Passive activity losses (**"PALs"**) of a taxpayer are the amounts of such taxpayer's losses from passive activities for a taxable year. Individuals and personal service corporations are entitled to deduct PALs only to the extent of their passive income whereas closely held C corporations (other than personal service corporations) can offset PALs against both passive and net active income, but not against portfolio (dividends, interest, etc.) income. In calculating passive income and loss, however, all passive activities of the taxpayer are aggregated. PALs disallowed as a result of the above rules will be suspended and can be carried forward indefinitely to offset future passive (or passive and active, in the case of a closely held C corporation) income.

On a taxpayer's disposition of his entire interest in a passive activity in a fully taxable transaction not involving a related party, any passive loss of such taxpayer that was suspended by the provisions of the passive activity loss rules is deductible against either passive or non-passive income.

Limited Partner Interests. Most Limited Partners' distributive shares of the Partnership's losses will be treated as PALs, the availability of which will be limited in each case to the individual Partner's passive income in all passive activities in which the Limited Partner has an interest. If a Limited Partner does not have sufficient passive income to utilize the PALs, the disallowed PALs will be suspended and may be carried forward to be deducted against passive income arising in future years. Further, on the disposition by a Limited Partner of his entire interest in the Partnership to an unrelated party in a fully taxable transaction, such suspended losses will be available, as described above.

Gain or Loss on Sale of Property or Units

In the event some or all of the property of the Partnership is sold, or on sale of a Unit, a Limited Partner will realize gain to the extent the amount realized exceeds his or her basis in the Partnership. In such case, there may be recapture, as ordinary income, of IDCs and depletion previously allocated to such Limited Partner. If the gain realized exceeds the amount of the recapture income, the Limited Partner will recognize capital gains for the balance.

It is possible that a Limited Partner will be required to recognize ordinary income pursuant to the recapture rules in excess of the taxable income on the disposition transaction or in a situation where the disposition transaction resulted in a taxable loss. To balance the excess income, the Limited Partner would recognize a capital loss for the difference between the gain and the income. Depending on a Limited Partner's particular tax situation, some or all of this loss might be deferred to future years, resulting in a greater tax liability in the year in which the sale was made and a reduced future tax liability.

Any partner who sells or exchanges interests in a partnership must generally notify the partnership in writing within 30 days of such transaction in accordance with Regulations and must attach a statement to his tax return reflecting certain facts regarding the sale or exchange. The notice must include names, addresses, and taxpayer identification numbers (if known) of the transferor and transferee and the date of the exchange. The partnership also is required to provide copies to the transferor and the transferee of information it is required to provide to the Service in connection with such a transfer.

Partnership Distributions

Under the Code, any increase in a partner's share of partnership liabilities, or any increase in such partner's individual liabilities by reason of an assumption by him or her of partnership liabilities is considered to be a contribution of money by the partner to the partnership. Similarly, any decrease in a partner's share of partnership liabilities or any decrease in such partner's individual liabilities by reason of the partnership's assumption of such individual liabilities will be considered as a distribution, a constructive distribution, of money to the partner by the partnership.

A Partner's adjusted basis in his or her Units will initially consist of the cash he or she contributes to the Partnership. His or her basis will be increased by his or her share of Partnership income and decreased by his or her share of Partnership losses and distributions. To the extent that actual or constructive distributions are in excess of a Partner's adjusted basis in his or her Partnership interest (after adjustment for contributions and his or her share of income and losses of the Partnership), that excess will generally be treated as gain from the sale of a capital asset. In addition, gain could be recognized to a distributee partner on the disproportionate distribution to a partner of unrealized receivables or substantially appreciated inventory. The Partnership Agreement prohibits distributions to a Limited Partner to the extent such distribution would create or increase a deficit in a Limited Partner's Capital Account.

Partnership Allocations

The Partners' distributive shares of partnership income, gain, loss, and deduction should be determined and allocated substantially in accordance with the terms of the Partnership Agreement.

The Service could contend that the allocations contained in the Partnership Agreement do not have substantial economic effect or are not in accordance with the Partners' interests in the Partnership and may seek to reallocate these items in a manner that will increase the income or gain or decrease the deductions allocable to a Partner.

Administrative Matters

Returns and Audits. While no federal income tax is required to be paid by an organization classified as a partnership for federal income tax purposes, a partnership must file federal income tax information returns which are subject to audit by the Service. Any such audit may lead to adjustments, in which event the Limited Partners may be required to file amended personal federal income tax returns. Any such audit may also lead to an audit of a Limited Partner's individual tax return and adjustments to items unrelated to an investment in Units.

For purposes of reporting, audit, and assessment of additional federal income tax, the tax treatment of "partnership items" is determined at the partnership level. Partnership items will include those items that the Regulations provide are more appropriately determined at the partnership level than the partner level. The Service generally cannot initiate deficiency proceedings against an individual partner with respect to partnership items without first conducting an administrative proceeding at the partnership level as to the correctness of the partnership's treatment of the item. An individual partner may not file suit for a credit or a refund arising out of a partnership item without first filing a request for an administrative proceeding by the Service at the partnership level. Individual partners are entitled to notice of such administrative proceedings and decisions therein, except in the case of partners with less than 1% profits interest in a partnership having more than 100 partners. If a group of partners having an aggregate profits interest of 5% or more in such a partnership so requests, however, the Service also must mail notice to a partner appointed by that group to receive notice. All partners, whether or not entitled to notice, are entitled to participate in the administrative proceedings at the partnership level, although the Partnership Agreement provides for waiver of certain of these rights by the Limited Partners. All Partners, including those not entitled to notice, may be bound by a settlement reached by the Partnership's representative, the "tax matters partner," which will be Unit Petroleum Company. If a proposed tax deficiency is contested in any court by any Partner or by the General Partner, all Partners may be deemed parties to such litigation and bound by the result reached therein.

Consistency Requirements. A partner must generally treat partnership items on his or her federal income tax returns consistently with the treatment of such items on the partnership information return unless he or she files a statement with the Service identifying the inconsistency or otherwise satisfies the requirements for waiver of the consistency requirement. Failure to satisfy this requirement will result in an adjustment to conform the partner's treatment of the item with the treatment of the item on the partnership return. Intentional or negligent disregard of the consistency requirement may subject a partner to substantial penalties.

<u>Compliance Provisions.</u> Taxpayers are subject to several penalties and other provisions that encourage compliance with the federal income tax laws, including an accuracy-related penalty in an amount equal to 20% of the portion of an underpayment of tax caused by negligence, intentional disregard of rules or regulations or any “substantial understatement” of income tax. For non-corporate taxpayers, a “substantial understatement” of tax is an understatement of income tax that exceeds the greater of (a) 10% of the tax required to be shown on the return (the correct tax), or (b) $5,000.

Except in the case of understatements attributable to “tax shelter” items, an item of understatement may not give rise to the penalty if (a) there is or was “substantial authority” for the taxpayer’s treatment of the item or (b) all facts relevant to the tax treatment of the item are disclosed on the return or on a statement attached to the return, and there is a reasonable basis for the tax treatment of such item by the taxpayer. In the case of partnerships, the disclosure is to be made on the return of the partnership. Under the applicable Regulations, however, an individual partner may make adequate disclosure with respect to partnership items if certain conditions are met.

In the case of understatements attributable to “tax shelter” items, the substantial understatement penalty may be avoided only if the taxpayer establishes that, in addition to having substantial authority for his or her position, he or she reasonably believed the treatment claimed was more likely than not the proper treatment of the item. A “tax shelter” item is one that arises from a partnership (or other form of investment) the principal purpose of which is the avoidance or evasion of federal income tax.

Based on the definition of a “tax shelter” in the Regulations, performance of previous partnerships, and the planned activities of the Partnership, the General Partner does not believe that the Partnership will qualify as a “tax shelter” under the Code, and will not register it as such.

Accounting Methods and Periods

The Partnership will use the accrual method of accounting and will select the calendar year as its taxable year.

State and Local Taxes

The opinions expressed herein are limited to issues of federal income tax law and do not address issues of state or local law. Prospective investors are urged to consult their tax advisors regarding the impact of state and local laws on an investment in the Partnership.

COMPETITION, MARKETS AND REGULATION

The oil and gas industry is highly competitive in all its phases. The Partnership will encounter strong competition from both major independent oil companies and individuals, many of which possess substantial financial resources, in acquiring economically desirable prospects and equipment and labor to operate and maintain Partnership Properties. There are likewise numerous companies and individuals engaged in the organization and conduct of oil and gas drilling programs and there is a high degree of competition among such companies and individuals in the offering of their programs.

Marketing of Production

The availability of a ready market for any oil and gas produced from Partnership Wells will depend on numerous factors beyond the control of the Partnership, including the extent of domestic production and importation of oil and gas, the proximity of Partnership Wells to gas pipelines and the capacity of such gas pipelines, the marketing of other competitive fuels, fluctuation in demand, governmental regulation of production, refining and transportation, general national and worldwide economic conditions, and the pricing, use and allocation of oil and gas and their substitute fuels.

The demand for gas decreased significantly in the 1980s due to economic conditions, conservation and other factors. As a result of such reduced demand and other factors, including the Power Plant and Industrial Fuel Use Act (the **“Fuel Use Act”**) which related to the use of oil and gas in the United States in certain fuel burning installations, many pipeline companies began purchasing gas on terms which were not as favorable to sellers as terms governing purchases of gas prior thereto. Spot market gas prices declined generally during that period.

While the Fuel Use Act has been repealed and the markets for gas have improved significantly recently, there can be no assurance that such improvement will continue. As a result, it is possible that there may be significant delays in selling any gas from Partnership Properties.

In the event the Partnership acquires an interest in a gas well or completes a productive gas well, or a well that produces both oil and gas, the well may be shut in for a substantial period of time for lack of a market if the well is in an area distant from existing gas pipelines. The well may remain shut in until such time as a gas pipeline, with available capacity, is extended to such an area or until such time as sufficient wells are drilled to establish adequate reserves which would justify the construction of a gas pipeline, processing facilities, if necessary, and a transmission system.

The worldwide supply of oil has been largely dependent on rates of production of foreign reserves. Although in recent years the demand for oil has slightly increased in this country, imports of foreign oil continue to increase. Consequently, historically the prices for domestic oil production have generally remained low. Future domestic oil prices will follow foreign prices which in turn will depend largely on the actions of foreign producers with respect to rates of production and it is virtually impossible to predict what actions those producers will take in the future. Prices may also be affected by political and other factors relating to the Middle East. As a result, it is possible that prices for oil, if any, produced from a Partnership Well will be lower than those currently available or projected at the time the interest therein is acquired. In view of the many uncertainties affecting the supply and demand for crude oil and natural gas, and the change in the makeup of the Congress of the United States and the resulting potential for a different focus for the United States energy policy, the General Partner is unable to predict what future gas and oil prices will be.

Regulation of Partnership Operations

Production of any oil and gas found by the Partnership will be affected by state and federal regulations. All states in which the Partnership intends to conduct activities have statutory provisions regulating the production and sale of oil and gas. Such statutes, and the regulations promulgated in connection therewith, generally are intended to prevent waste of oil and gas and to protect correlative rights and the opportunities to produce oil and gas as between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and gas produced by assigning allowable rates of production to each well or proration unit. Pertinent state and federal statutes and regulations also extend to the prevention and clean-up of pollution. These laws and regulations are subject to change and no predictions can be made as to what changes may be made or the effect of such changes on the Partnership's operations.

Under the laws and administrative regulations of the State of Oklahoma regarding forced pooling, owners of oil and gas leases or unleased mineral interests may be required to elect to participate in the drilling of a well with other fractional undivided interest owners within an established spacing unit or to sell or farm out their interest therein. The terms of any such sale or farm-out are generally those determined by the Oklahoma Corporation Commission to be equal to the most favorable terms then available in the area in arm's length transactions although there can be no assurance that this will be the case. In addition, if properties become the subject of a forced pooling order, drilling operations may have to be undertaken at a time or with other parties which the General Partner feels may not be in the best interest of the Partnership. In such event, the Partnership may have to farm out or assign its interest in such properties. In addition, if a property which might otherwise be acquired by the Partnership becomes subject to such an order, it may become unavailable to the Partnership. Finally, as a result of forced pooling proceedings involving a Partnership Property, the Partnership may acquire a larger than anticipated interest in such property, thereby increasing its share of the costs of operations to be conducted.

Natural Gas Price Regulation

Partnership Revenues are likely to be dependent on the sale and transportation of natural gas that may be subject to regulation by the Federal Energy Regulatory Commission ("FERC"). Historically the sale of natural gas has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA") and/or the Natural Gas Policy Act of 1978 ("NGPA"). The NGA conferred jurisdiction on the FERC's predecessor, the Federal Power Commission, to regulate the interstate transportation and sale of natural gas. The Act also established a certification system and required the FERC to ensure that all rates were "just and reasonable" and that natural gas companies did not grant "undue preference[s]." Under this system, the FERC regulated both the wellhead price and the price charged by pipelines to end-users and local distribution companies.

The NGPA began the gradual deregulation of prices at the wellhead. Under the NGPA, 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 the Partnership’s natural gas properties will be 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.

Commencing in 1985, the FERC, through Order Nos. 436, 500, 636 and 637, promulgated changes that significantly affect the transportation and marketing of gas. These changes have been intended to foster competition in the gas industry by, among other things, inducing or mandating that interstate pipeline companies provide nondiscriminatory transportation services to producers, distributors, buyers and sellers of gas and other shippers (so-called “open access” requirements). The FERC has also sought to expedite the certification process for new services, facilities, and operations of those pipeline companies providing “open access” services.

In 1992, the FERC issued Order 636 which, among other things, required each interstate pipeline company to “unbundle” its traditional wholesale services and create and make available on an open and nondiscriminatory basis numerous constituent services (such as gathering services, storage services, firm and interruptible transportation services, and stand-by sales services) and to adopt a new rate-making methodology to determine appropriate rates for those services. Each pipeline company was required to develop the specific terms of service in individual proceedings. The availability of non-discriminatory transportation services and the ability of pipeline customers to modify or terminate their existing purchase obligations under these regulations have greatly enhanced the ability of producers to market their gas directly to end users and local distribution companies.

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. The General Partner believes 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. The General Partner cannot predict what new or different regulations the FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on Partnership Revenue.

Oil Price Regulation

With respect to oil pipeline rates subject to the FERC’s jurisdiction under the Interstate Commerce Act, in October 1993 the FERC issued Order 561 to implement the requirements of Title XVIII of the Energy Policy Act of 1992. Order 561 established an indexing system, effective January 1, 1995, under which many oil pipelines are able to readily change their rates to track changes in the Producer Price Index for Finished Goods (PPI-FG), minus one percent. This index established ceiling levels for rates. Order 561 also permits cost-of-service proceedings to establish just and reasonable rates. The Order does not alter the right of a pipeline to seek FERC authorization to charge market rates. However, until the FERC makes the finding that the pipeline does not exercise significant market power, the pipeline’s rates cannot exceed the applicable index ceiling level or a level justified by the pipeline’s cost of service.

State Regulation of Oil and Gas Production

Most states in which the Partnership may conduct oil and gas activities regulate the production and sale of oil and natural gas. Those states generally impose requirements or restrictions for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. In addition, most states regulate the rate of production and may establish maximum daily production allowable from both oil and gas wells on a market demand or conservation basis. Until recently there has been no limit on allowable daily production on the basis of market demand, although at some locations production continues to be regulated for conservation or market purposes. In 1992 Oklahoma and Texas imposed additional limitations on gas production to more closely track market demand. The General Partner cannot predict whether any state regulatory agency may issue additional allowable reductions which may adversely affect the Partnership’s ability to produce its gas reserves.

Legislative and Regulatory Production and Pricing Proposals

A number of legislative and regulatory proposals continually are advanced which, if put into effect, could have an impact on the petroleum industry. The various proposals involve, among other things, an oil import fee, restructuring how oil pipeline rates are determined and implemented reducing production allowables, providing purchasers with "market-out" options in existing and future gas purchase contracts, eliminating or limiting the operation of take-or-pay clauses, eliminating or limiting the operation of "indefinite price escalator clauses" (e.g., pricing provisions which allow prices to escalate by means of reference to prices being paid by other purchasers of natural gas or prices for competing fuels), and state regulation of gathering systems. Proposals concerning these and other matters have been and will be made by members of the President's office, Congress, regulatory agencies and special interest groups. The General Partner cannot predict what legislation or regulatory changes, if any, may result from such proposals or any effect therefrom on the Partnership.

The effect of these regulations could be to decrease allowable production on Partnership Properties and thereby to decrease Partnership Revenues. However, by decreasing the amount of natural gas available in the market, such regulations could also have the effect of increasing prices of natural gas, although there can be no assurance that any such increase will occur. There can also be no assurance that the proposed regulations described above will be adopted or that they will be adopted on the terms set forth above. Additionally, such proposals, if adopted, are likely to be challenged in the courts and there can be no assurance as to the timing or the outcome of any such challenge.

Production and Environmental Regulation

Certain states in which the Partnership may drill and own productive properties control production from wells through regulations establishing the spacing of wells, limiting the number of days in a given month during which a well can produce and otherwise limiting the rate of allowable production.

In addition, the federal government and various state governments have adopted laws and regulations regarding protection of the environment. These laws and regulations may require the acquisition of a permit before or after drilling commences, impose requirements that increase the cost of operations, prohibit drilling activities on certain lands lying within wilderness areas or other environmentally sensitive areas and impose substantial liabilities for pollution resulting from drilling operations, particularly operations in offshore waters or on submerged lands.

A past, present, or future release or threatened release of a hazardous substance into the air, water, or ground by the Partnership or as a result of disposal practices may subject the Partnership to liability under the Comprehensive Environmental Response, Compensation and Liability Act, as amended (**"CERCLA"**), the Resource Conservation Recovery Act (**"RCRA"**), the Clean Water Act, and/or similar state laws, and any regulations promulgated pursuant thereto. Under CERCLA and similar laws, the Partnership may be fully liable for the cleanup costs of a release of hazardous substances even though it contributed to only part of the release. While liability under CERCLA and similar laws may be limited under certain circumstances, typically the limits are so high that the maximum liability would likely have a significant adverse effect on the Partnership. In certain circumstances, the Partnership may have liability for releases of hazardous substances by previous owners of Partnership Properties. Additionally, the discharge or substantial threat of a discharge of oil by the Partnership into United States waters or onto an adjoining shoreline may subject the Partnership to liability under the Oil Pollution Act of 1990 and similar state laws. While liability under the Oil Pollution Act of 1990 is limited under certain circumstances, the maximum liability under those limits would still likely have a significant adverse effect on the Partnership. The Partnership's operations generally will be covered by the insurance carried by the General Partner or UNIT, if any. However, there can be no assurance that such insurance coverage will always be in force or that, if in force, it will adequately cover any losses or liability the Partnership may incur.

Violation of environmental legislation and regulations may result in the imposition of fines or civil or criminal penalties and, in certain circumstances, the entry of an order for the removal, remediation and abatement of the conditions, or suspension of the activities, giving rise to the violation. The General Partner believes that the

Partnership will comply with all orders and regulations applicable to its operations. However, in view of the many uncertainties with respect to the current controls, including their duration and possible modification, the General Partner cannot predict the overall effect of such controls on such operations. Similarly, the General Partner cannot predict what future environmental laws may be enacted or regulations may be promulgated and what, if any, impact they would have on operations or Partnership Revenue.

SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT

The business and affairs of the Partnership and the respective rights and obligations of the Partners will be governed by the Agreement. The following is a summary of certain pertinent provisions of the Agreement which have not been as fully discussed elsewhere in this Memorandum but does not purport to be a complete description of all relevant terms and provisions of the Agreement and is qualified in its entirety by express reference to the Agreement. Each prospective subscriber should carefully review the entire Agreement.

Partnership Distributions

The General Partner will make quarterly determinations of the Partnership's cash position. If it determines that excess cash is available for distribution, it will be distributed to the Partners in the same proportions that Partnership Revenue has been allocated to them after giving effect to previous distributions and to portions of such revenues theretofore used or expected to be thereafter used to pay costs incurred in conducting Partnership operations or to repay Partnership borrowings. It is expected that no cash distributions will be made earlier than the first quarter of 2008. Distributions of cash determined by the General Partner to be available therefore will be made to the Limited Partners quarterly and to the General Partner at any time. All Partnership funds distributed to the Limited Partners shall be distributed to the persons who were record holders of Units on the day on which the distribution is made. Thus, regardless of when an assignment of Units is made, any distribution with respect to the Units which are assigned will be made entirely to the assignee without regard to the period of time prior to the date of such assignment that the assignee holds the Units.

The Partnership will terminate automatically on December 31, 2037 unless prior thereto the General Partner or Limited Partners holding a majority of the outstanding Units elect to terminate the Partnership as of an earlier date. On termination of the Partnership, the debts, liabilities and obligations of the Partnership will be paid and the Partnership's oil and gas properties and any tangible equipment, materials or other personal property may be sold for cash. The cash received will be used to make certain adjusting payments to the Partners (see "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Termination"). Any remaining cash and properties will then be distributed to the Partners in proportion to and to the extent of any remaining balances in the Partners' capital accounts and then in undivided percentage interests to the Partners in the same proportions that Partnership Revenues are being shared at the time of such termination (see "SUMMARY OF THE LIMITED PARTNERSHIP AGREEMENT — Termination").

Deposit and Use of Funds

Until required in the conduct of the Partnership's business, Partnership funds, including, but not limited to, the Capital Contributions, Partnership Revenue and proceeds of borrowings by the Partnership, will be deposited, with or without interest, in one or more bank accounts of the Partnership in a bank or banks to be selected by the General Partner or invested in short-term United States government securities, money market funds, bank certificates of deposit or commercial paper rated as "A1" or "P1" as the General Partner, in its sole discretion, deems advisable. Any interest or other income generated by such deposits or investments will be for the Partnership's account. Except for Capital Contributions, Partnership funds from any of the various sources mentioned above may be commingled with funds of the General Partner and may be used, expended and distributed as authorized by the terms and provisions of the Agreement. The General Partner will be entitled to prompt reimbursement of expenses it incurs on behalf of the Partnership.

Power and Authority

In managing the business and affairs of the Partnership, the General Partner is authorized to take such action as it considers appropriate and in the best interests of the Partnership (see Section 10.1 of the Agreement). The

General Partner is authorized to engage legal counsel and otherwise to act with respect to Service audits, assessments and administrative and judicial proceedings as it deems in the best interests of the Partnership and pursuant to the provisions of the Code.

The General Partner is granted a broad power of attorney authorizing it to execute certain documents required in connection with the organization, qualification, continuance, modification and termination of the Partnership on behalf of the Limited Partners (see Sections 1.5 and 1.6 of the Agreement). Certain actions, such as an assignment for the benefit of its creditors or a sale of substantially all of the Partnership Properties, except in connection with the termination, roll-up or consolidation of the Partnership, cannot be taken by the General Partner without the consent of a majority in interest of the Limited Partners and the receipt of an opinion of Counsel as described under "Assignments by the General Partner" below (see Sections 10.15 and 12.1 of the Agreement).

The Agreement provides that the General Partner will either conduct the Partnership's drilling and production operations and operate each Partnership Well or arrange for a third party operator to conduct such operations. The General Partner will, on behalf of the Partnership, enter into an appropriate operating agreement with the other owners of properties to be developed by the Partnership authorizing either the General Partner or a third party operator to conduct such operations. The Partnership Agreement further provides that the Partnership will take such action in connection with operations pursuant to such operating agreements as the General Partner, in its sole discretion, deems appropriate and in the best interests of the Partnership, and the decision of the General Partner with respect thereto will be binding on the Partnership.

Rollup or Consolidation of the Partnership

Two years or more after the Partnership has completed substantially all of its property acquisition, drilling and development operations, the General Partner may, without the vote, consent or approval of the Limited Partners, cause all or substantially all of the oil and gas properties and other assets of the Partnership to be sold, assigned or transferred to, or the Partnership merged or consolidated with, another partnership or a corporation, trust or other entity for the purpose of combining the assets of two or more of the oil and gas partnerships formed for investment or participation by employees, directors and/or consultants of UNIT or any of its subsidiaries; provided, however, that the valuation of the oil and gas properties and other assets of all such participating partnerships for purposes of such transfer or combination shall be made on a consistent basis and in a manner which the General Partner and UNIT believe is fair and equitable to the Limited Partners. As a consequence of any such transfer or combination, the Partnership will be dissolved and terminated and the Limited Partners shall receive partnership interests, stock or other equity interests in the transferee or resulting entity. See "RISK FACTORS—Investment Risks - Roll-Up or Consolidation of the Partnership."

Limited Liability

Under the Act, a limited partner is not generally liable for partnership obligations unless he or she takes part in the control of the business. The Agreement provides that the Limited Partners cannot bind or commit the Partnership or take part in the control of its business or management of its affairs, and that the Limited Partners will not be personally liable for any debts or losses of the Partnership. However, the amounts contributed to the Partnership by the Limited Partners and the Limited Partners' interests in Partnership assets, including amounts of undistributed Partnership Revenue allocable to the Limited Partners, will be subject to the claims of creditors of the Partnership. A Limited Partner (or his or her estate) will be obligated to contribute cash to the Partnership, even if the Limited Partner is unable to do so because of death, disability or any other reason, for:

(1) any unpaid contribution which the Limited Partner agreed to make to the Partnership; and

(2) any return, in whole or in part, of the Limited Partner's contribution to the extent necessary to discharge Partnership liabilities to all creditors who extended credit or whose claims arose before such return.

Liability of a Limited Partner is limited by the Act to one year for any return of his or her contribution not in violation of the Partnership Agreement or such Act and six years on any return of his or her contribution in violation of the Partnership Agreement or such Act. A partner is deemed to have received a return of his or her contribution to the extent that a distribution to him or her reduces his or her share of the fair value of the net assets of the Partnership below the value of his or her contribution which has not been distributed to him or her. How this provision applies to a partnership whose primary assets are producing oil and gas properties or other depleting assets is not entirely clear. The Agreement provides that for the purposes of this provision, the value of a Limited Partner's contribution which has not been distributed to him or her at any point in time will be the Limited Partner's Percentage of the stated capital of the Partnership allocated to the Limited Partners as reflected in its financial statements as of such point in time.

Maintenance of limited liability of the Limited Partners in other jurisdictions in which the Partnership may operate may require compliance with certain legal requirements of those jurisdictions. In such jurisdictions, the General Partner shall cause the Partnership to operate in such a manner as it, on the advice of responsible Counsel, deems appropriate to avoid unlimited liability for the Limited Partners (see Sections 1.5, 12.1 and 12.2 of the Agreement). After the termination of the Partnership, any distribution of Partnership Properties to the Limited Partners would result in their having unlimited liability with respect to such properties.

Although the Partnership will, with certain limited exceptions, serve as a co-general partner of any drilling or income programs formed by UNIT or UPC in 2007 (see "PROPOSED ACTIVITIES"), the general liability of the Partnership will not flow through to the Limited Partners.

Records, Reports and Returns

The General Partner will maintain adequate books, records, accounts and files for the Partnership and keep the Limited Partners informed by means of written interim reports rendered within 60 days after each quarter of the Partnership's fiscal year. The reports will set forth the source and disposition of Partnership Revenues during the quarter.

Engineering reports on the Partnership Properties will be prepared by the General Partner for each year for which the General Partner prepares such a report in connection with its own activities. Such report will include an estimate of the total oil and gas proven reserves of the Partnership, the dollar value thereof and the value of the Limited Partners' interest in such reserve value. The report shall also contain an estimate of the life of the Partnership Properties and the present worth of the reserves. Each Limited Partner will receive a summary statement of such report which will reflect the value of the Limited Partners' interest in such reserves.

The General Partner will timely file the Partnership's income tax returns and by March 15 of each year or as soon thereafter as practicable, furnish each person who was a Limited Partner during the prior year all available information necessary for inclusion in his or her federal income tax return. (See Section 8.1 of the Agreement).

Transferability of Interests

Restrictions. A Limited Partner may not transfer or assign Units except for certain transfers:

- to the General Partner;
- to or for the benefit of himself or herself, his or her spouse, or other members of the transferor Limited Partner's immediate family sharing the same residence;
- to any corporation or other entity whose beneficial owners are all Limited Partners or permitted assignees;
- by the General Partner to any person who at the time of such transfer is an employee of the General Partner, UNIT or its subsidiaries; and
- by reason of death or operation of law.

Further, no sale or exchange of any Units may be made if the sale of such interest would, in the opinion of counsel for the Partnership, result in a termination of the Partnership for purposes of Section 708 of the Code, violate any applicable securities laws or cause the Partnership to be treated as an association taxable as a corporation or publicly traded partnership for federal income tax purposes; provided, however, that this condition may be waived by the General Partner, in its sole discretion. Moreover, in no event shall all or any portion of a Limited Partner's Units be assigned to a minor or an incompetent, except by will, intestate succession, in trust, or pursuant to the Uniform Transfers to Minors Act.

As the offer and sale of the Units are not being registered under the Securities Act of 1933, as amended, they may be sold, transferred, assigned or otherwise disposed of by a Limited Partner only if, in the opinion of counsel for the Partnership, such transfer or assignment would not violate, or cause the offering of the Units to be volative of, such act or applicable state securities laws, including investor suitability standards thereunder. Because of the structure and anticipated operation of the Partnership, Rule 144 under the Securities Act of 1933 will not be available to Limited Partners in connection with any such sales.

Assignees. An assignee of a Limited Partner does not automatically become a Substituted Limited Partner, but has the right to receive the same share of Partnership Revenue and distributions thereof to which the assignor Limited Partner would have been entitled. A Limited Partner who assigns his or her Partnership interest ceases to be a Limited Partner, except that until a Substituted Limited Partner is admitted in his or her place, the assignor retains the statutory rights of an assignor of a Limited Partner's interest under the partnership laws of the State of Oklahoma. The assignee of a Partnership interest who does not become a Substituted Limited Partner and desires to make a further assignment of such interest is subject to all of the restrictions on transferability of Partnership interests described herein and in the Partnership Agreement.

In the event of the death, incapacity or bankruptcy of a Limited Partner, his or her legal representatives will have all the rights of a Limited Partner only for the purpose of settling or liquidating his or her estate and such power as the decedent, incompetent or bankrupt Limited Partner possessed to assign all or any part of his or her interest in the Partnership and to join with such assignee in satisfying conditions precedent to such assignee's becoming a Substituted Limited Partner.

A purported sale, assignment or transfer of a Limited Partner's interest will be recognized by the Partnership when it has received written notice of such sale or assignment in form satisfactory to the General Partner, signed by both parties, containing the purchaser's or assignee's acceptance of the terms of the Agreement and a representation by the parties that the sale or assignment was lawful. Such sale or assignment will be recognized as of the date of such notice, except that if such date is more than 30 days prior to the time of filing, such sale or assignment will be recognized as of the time the notice was filed with the Partnership. Distributions of Partnership Revenue will be made only to those persons who were record owners of Units on the day any such distribution is made.

Substituted Limited Partners. No Limited Partner has the right to substitute an assignee as a Limited Partner in his or her place. The General Partner, however, has the right in its sole discretion to permit such assignee to become a Substituted Limited Partner and any such permission by the General Partner is binding and conclusive without the consent or approval of any Limited Partner. Any Substituted Limited Partner must, as a condition to receiving any interest of the Limited Partner, agree in writing to be bound by the terms and conditions of the Partnership Agreement, pay or agree to pay the costs and expenses incurred by the Partnership in taking the actions necessary in connection with his or her substitution as a Limited Partner and satisfy the other conditions specified in Article XIII of the Partnership Agreement.

Assignments by the General Partner. The General Partner may not sell, assign, transfer or otherwise dispose of its interest in the Partnership except with the prior consent of a majority in interest of the Limited Partners, provided that no such consent is required if the sale, assignment or transfer is pursuant to a bona fide merger, other corporate reorganization or complete liquidation, sale of substantially all of the General Partner's assets (provided the purchasers agree to assume the duties and obligations of the General Partner) or any sale or transfer to UNIT or any affiliate of UNIT. Any consent of the Limited Partners will not be effective without an opinion of counsel to the Partnership or an order or judgment of a court of competent jurisdiction to the effect that the exercise of such right will not be deemed to evidence that the Limited Partners are taking part in the management of the Partnership's business and affairs and will not result in a loss of any Limited Partner's limited liability or cause the Partnership to be classified as an association taxable as a corporation or publicly traded partnership for federal income tax purposes (see Section 12.1 of the Agreement). Any transferee of the General Partner's interest may become a substitute General Partner by assuming and agreeing to perform all of the duties and obligations of a General Partner under the Agreement. In such event, the transferring General Partner, on making a proper accounting to the substitute General Partner, will be relieved of any further duties or obligations with respect to any future Partnership operations.

Amendments

The Agreement may be amended on the approval by a majority in interest of the Limited Partners, except that amendments changing the Partners' participation in costs and revenues, increasing or decreasing the General Partner's compensation or otherwise materially and adversely affecting the interests of either the Limited Partners or the General Partner must be approved by all Limited Partners if their interests would be adversely affected thereby or by the General Partner if its interest would be adversely affected thereby. The Limited Partners have no right to propose amendments to the Agreement.

Voting Rights

Under the Agreement, the Limited Partners will have very limited rights to vote on any Partnership matters. Except for certain special amendments referred to under "Amendments" above, matters submitted to the Limited Partners for determination will be determined by the affirmative vote of Limited Partners holding a majority of the outstanding Units. Units held by the General Partner may be voted by it.

Generally, Limited Partners owning more than 50% of the outstanding Units of the Partnership may, without the necessity of concurrence by the General Partner, vote to:

- Approve the execution or delivery of any assignment for the benefit of the Partnership's creditors;
- Approve the sale or disposal of all or substantially all of the Partnership's assets, except pursuant to (i) a rollup or consolidation of the Partnership (see "Rollup or Consolidation of the Partnership" above) or (ii) termination (see "Termination" below);
- Approve the General Partner's sale, assignment, transfer or disposal of its interest in the Partnership, unless such sale, assignment or transfer is pursuant to (i) a merger or other corporate reorganization, or liquidation or sale of substantially all of its assets, and the purchaser agrees to assume the duties and obligations of the General Partner, or (ii) any sale to UNIT or its affiliates;
- Terminate and dissolve the Partnership; or
- Approve any amendments to the Agreement which may be proposed by the General Partner;

provided, however, any approvals, consents or elections of the Limited Partners will not become effective unless prior to the exercise thereof the General Partner is furnished with an opinion of counsel for the Partnership, or an order or judgment of any court of competent jurisdiction, that the exercise of such rights:

- Will not be deemed to evidence that the Limited Partners are taking part in the control or management of the Partnership's business affairs;
- Will not result in the loss of any Limited Partner's limited liability under the Act; and
- Will not result in the Partnership being classified as an association taxable as a corporation for federal income tax purposes.

Exculpation and Indemnification of the General Partner

Pursuant to the Agreement, neither the General Partner or any affiliate thereof will have any liability to the Partnership or to any Partners therein for any loss suffered by the Partnership or such Partner that arises out of any action or inaction of the General Partner or any affiliate thereof if the General Partner or affiliate thereof in good faith determined that such course of conduct was in the best interest of the Partnership, the General Partner or affiliate was acting on behalf of or performing services for the Partnership, such liability or loss was not the result of gross negligence or willful misconduct by the General Partner or affiliates thereof, and payments arising from such indemnification or agreement to hold harmless are receivable only out of the tangible net assets of the Partnership.

Termination

The Partnership will terminate automatically on December 31, 2037. In addition, on the dissolution (other than pursuant to a merger, or other corporate reorganization or sale), bankruptcy, legal disability or withdrawal of the General Partner, the Partnership shall immediately be dissolved and terminated. The Act provides, however, that the Limited Partners may elect to reform and reconstitute themselves as a limited partnership within 90 days after such dissolution under the provisions in the Partnership Agreement or under any other terms. The Partnership may terminate sooner if a majority in interest of the Limited Partners or the General Partner elects to dissolve and terminate the Partnership as of an earlier date. Such right to accelerate termination of the Partnership by the Limited Partners will not be available unless prior to any exercise thereof the Limited Partners proposing such termination obtain and furnish to the General Partner an opinion, order or judgment in the form referred to above under “Transferability of Interests - Assignments by the General Partner.” The withdrawal, expulsion, dissolution, death, legal disability, bankruptcy or insolvency of any Limited Partner will not effect a dissolution or termination of the Partnership. In the event of an election to terminate the Partnership prior to expiration of its stated terms, 90 days’ prior written notice must be given to all Partners specifying the termination date which must be the last day of a calendar month following such 90 day period unless an earlier date is approved by Limited Partners holding a majority of the outstanding Units.

When the Partnership is terminated, there will be an accounting with respect to its assets, liabilities and accounts. The Partnership’s physical property and its oil and gas properties may be sold for cash. Except in the case of an election by the General Partner to terminate the Partnership before the tenth anniversary of the Effective Date, Partnership Properties may be sold to the General Partner or any of its affiliates for their fair market value as determined in good faith by the General Partner.

On termination, all of the Partnership’s debts, liabilities and obligations, including expenses incurred in connection with the termination and the sale or distribution of Partnership assets, will be paid. All Partnership borrowings will be paid in full. When the specified payments have all been made, the remaining cash and properties of the Partnership, if any, will be distributed to the Partners as set forth under “Partnership Distributions” above (see Section 16.4 of the Agreement). Such distribution will result in the Limited Partners’ having unlimited liability with respect to any Partnership Properties distributed to them.

Insurance

The General Partner will use its best efforts to obtain such insurance as it deems prudent to serve as protection against liability for loss and damage. Such insurance may include, but is not limited to, public liability, automotive liability, workers’ compensation and employer’s liability insurance and blowout and control of well insurance.

COUNSEL

Conner & Winters, LLP, 4000 One Williams Center, Tulsa, Oklahoma 74172-0148, has acted as special counsel to the General Partner in connection with certain aspects of this offering. Conner & Winters has assisted in the preparation of the Agreement and this Memorandum. In connection with the preparation of this Memorandum, Conner & Winters has relied entirely on information submitted to it by the General Partner. Certain of this information has been verified by Conner & Winters in the course of its representation, but no systematic effort has been made to verify all of the material information contained herein, and much of such information is not subject to independent verification. In addition, Conner & Winters has made no independent investigation of the financial information concerning the General Partner. Further, while passing on certain legal matters, Conner & Winters has not passed on the investment merits nor is it qualified to do so. Because substantial portions of the information contained in this Memorandum have not been independently verified, each investor must make whatever independent inquiries the investor or his or her advisors deem necessary or desirable to verify or confirm the statements made herein.

GLOSSARY

As used herein and in the Agreement, the following terms and phrases will have the meanings indicated.

(a) **"*Additional Assessments*"** are amounts required to be contributed by the Limited Partners to the Partnership on a call therefore by the General Partner in the manner described under "ADDITIONAL FINANCING — Additional Assessments."

(b) An **"*affiliate*"** of another person is (1) any person directly or indirectly owning, controlling or holding with power to vote 10% or more of the outstanding voting securities of such other person; (2) any person 10% or more of whose outstanding voting securities are directly or indirectly owned, controlled, or held with power to vote, by such other person; (3) any person directly or indirectly controlling, controlled by, or under common control with such other person; (4) any officer, director, trustee or partner of such other person; and (5) if such other person is an officer, director, trustee or partner, any company for which such person acts in any such capacity.

(c) The **"*Aggregate Subscription*"** is the sum of the Capital Subscriptions of all Limited Partners.

(d) **"*Agreement*"** and **"*Partnership Agreement*"** refers to the Agreement of Limited Partnership attached as Exhibit A to this Private Offering Memorandum.

(e) The **"*Capital Contribution*"** of a Limited Partner is the amount of the Capital Subscription actually paid in by him or her, or by any predecessor in interest, to the capital of the Partnership including any payments made by deductions from salary. The "Capital Contribution" of the General Partner includes the amounts contributed to the Partnership or paid by the General Partner or by any Limited Partner whose Units are purchased by the General Partner pursuant to Section 4.2 of the Agreement because of a default by such Limited Partner in the payment of an Installment or pursuant to Article XV of the Agreement, including payments made by deductions from the salary of such Limited Partner.

(f) The **"*Capital Subscription*"** of a Limited Partner or his or her assignee (including the General Partner where Units are transferred pursuant to Section 4.2 of the Agreement) is the amount specified in the Subscription Agreement executed by such Limited Partner for payment by him or her to the capital of the Partnership in accordance with the provisions of the Agreement, reduced by the amounts thereof from which the Limited Partners have been released by the General Partner of their obligation to pay.

(g) A **"*Development Well*"** means a well intended to be drilled within the proved areas of a known oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(h) **"*Director*"** refers to the duly elected directors of UNIT as well as all honorary directors and consultants to the Board of Directors of UNIT.

(i) **"*Drilling Costs*"** are those costs incurred in drilling, testing, completing and equipping a well to the point that it proves to be dry and is abandoned or is ready to commence commercial production of oil or gas therefrom.

(j) **"*Effective Date*"** refers to the date on which the certificate evidencing formation of the Partnership is filed with the Secretary of State of the State of Oklahoma as required by the Act (54 Okla. Stat. 2001, Section 309).

(k) An **"*Exploratory Well*"** means a well drilled to find production in an unproven area, to find a new reservoir in a field previously found to be productive or to extend greatly the limits of a known reservoir.

(l) A **"*farm-out*"** is an agreement whereby the owner of an oil and gas property agrees to assign such property, usually retaining some interest therein such as an overriding royalty, a production payment, a net profits interest or a carried working interest, subject in most cases, however, to the drilling of one or more wells or other performance by the prospective assignee as a condition of the assignment.

(m) The **"*General Partner's Minimum Capital Contribution*"** is that amount equal to the total of (i) all Partnership costs and expenses charged to its account from the time of the formation of the Partnership through December 31, 2007, plus (ii) the General Partner's estimate of the total Leasehold Acquisition Costs and Drilling Costs expected to be incurred by the Partnership subsequent to December 31, 2007, if any, minus (iii) the amount, if any, of the unexpended Aggregate Subscription at December 31, 2007.

(n) The **“*General Partner’s Percentage*”** is that percentage determined by dividing the amount of the General Partner’s Minimum Capital Contribution by the total of (i) the General Partner’s Minimum Capital Contribution plus (ii) the Aggregate Subscription.

(o) **“*Installments*”** refer to the periodic payments of the Capital Subscription, which are payable either (i) in four equal installments due on March 15, June 15, September 15, 2007 and December 15, 2007, respectively, or (ii) if an employee so elects, through equal deductions from 2007 salary commencing immediately after formation of the Partnership.

(p) **“*Leasehold Acquisition Costs*”** with respect to properties, if any, acquired by the Partnership from non-affiliated parties mean the actual costs to the Partnership of and in acquiring the properties, and, with respect to properties acquired by the Partnership from the General Partner, UNIT or its affiliates are, without duplication, the sum of:

(1) the prices paid by the General Partner, UNIT or its affiliates in acquiring an oil and gas property, including purchase option fees and charges, bonuses and penalties, if any;

(2) title insurance or examination costs, broker’s commissions, filing fees, recording costs, transfer taxes, if any, and like charges incurred in connection with the acquisition of such property;

(3) a pro rata portion of the actual, necessary and reasonable expenses of the General Partner, UNIT or its affiliates for seismic and geophysical services;

(4) rentals, shut-in royalties and ad valorem taxes paid by the General Partner, UNIT or its affiliates with respect to such property to the date of its transfer to the Partnership;

(5) interest and points actually incurred on funds used by the General Partner, UNIT or its affiliates to acquire or maintain such property; and

(6) such portion of the General Partner’s, UNIT or its affiliates’ reasonable, necessary and actual expenses for geological, engineering, drafting, accounting, legal and other like services allocated to the acquisition, operations and maintenance of the property in accordance with generally accepted industry practices, except for expenses in connection with the past drilling of wells which are not producers of sufficient quantities of oil or gas to make commercially reasonable their continued operations, and provided that the costs and expenses enumerated in (4), (5) and (6) above with respect to any particular property shall have been incurred not more than thirty-six (36) months prior to the acquisition of such property by the Partnership.

In the event a fractional undivided interest in a property is sold or transferred by the General Partner, UNIT or any affiliate to an unaffiliated third party for an amount in excess of that portion of the original cost of the property attributable to the transferred interest, the amount of such excess shall not reduce or be offset against the amount of the Leasehold Acquisition Costs attributable to any interest in the same property which is transferred to the Partnership.

(q) **“*Limited Partners*”** are those persons who acquire Units in the Partnership on its formation and those transferees of Units who are accepted as Substituted Limited Partners. The General Partner may also be a Limited Partner if it subscribes for Units or if it subsequently acquires Units by (i) the exercise by a Limited Partner of his or her right of presentment; (ii) a purchase by the General Partner of the Units of a Limited Partner who defaults in the payment of an Installment; or (iii) any other assignment or transfer.

(r) The **“*Limited Partners’ Percentage*”** is that percentage determined by dividing the amount of the Aggregate Subscription by the total of (i) the General Partner’s Minimum Capital Contribution plus (ii) the Aggregate Subscription.

(s) **“*Normal Retirement*”** means retirement under the terms of a pension or similar retirement plan adopted by the General Partner, UNIT or any subsidiary with whom a Limited Partner is employed as in effect at the time of retirement.

(t) ***"Oil and gas properties"*** are oil and gas leasehold working interests, fee interests, mineral interests, royalty interests, overriding royalty interests, production payments, options or rights to lease or acquire such interests, geophysical exploration permits and any tangible or intangible properties or other rights incident thereto, whether real, personal or mixed.

(u) ***"Operating Expenses"*** are expenditures made and costs incurred in producing and marketing oil or gas from completed wells, including, in addition to labor, fuel, repairs, hauling, material, supplies, utility charges and other costs incident to or necessary for the maintenance or operation of such wells or the marketing of production therefrom, ad valorem, severance and other such taxes (other than windfall profit taxes), insurance and casualty loss expense and compensation to well operators or others for services rendered in conducting such operations.

(v) The General Partner and the Limited Partners are sometimes collectively referred to as the ***"Partners***."

(w) ***"Partnership Agreement"*** and ***"Agreement"*** refer to the Agreement of Limited Partnership attached as Exhibit A to this Private Offering Memorandum.

(x) The ***"Partnership Properties"*** are oil and gas properties or interests therein acquired by the Partnership or properties acquired by any partnership or joint venture in which the Partnership is a partner or joint venturer, whether acquired by purchase, option exercise or otherwise.

(y) ***"Partnership Revenue"*** refers to the Partnership's gross revenues from all sources, including interest income, proceeds from sales of production, the Partnership's share of revenues from partnerships or joint ventures of which it is a member, sales or other dispositions of Partnership Properties or other Partnership assets, provided that contributions to Partnership capital by the Partners and the proceeds of any Partnership borrowings are specifically excluded and dry-hole and bottom-hole contributions shall be treated as reductions of the costs giving rise to the right to receive such contributions.

(z) ***"Partnership Wells"*** are any and all of the oil and gas wells in which the Partnership has an interest, either directly or indirectly through any other partnership or joint venture.

(aa) ***"Productive properties"*** are oil and gas properties that have been tested by drilling and determined to be capable of producing oil or gas in commercial quantities.

(bb) A ***"spacing unit"*** is a drilling and spacing, production or similar unit established by any regulatory body with jurisdiction, or in the absence of such a regulatory body or action thereby, the acreage attributable to wells drilled under the normal spacing pattern in such area or if no such spacing unit is designated, in keeping with generally accepted industry practices, or the largest of such units in the event of multiple objective formations.

(cc) ***"Special Production and Marketing Costs"*** are costs and expenses that are not normally and customarily incurred in connection with drilling, producing and marketing operations, including without limitation, costs incurred in constructing compressor plants, gasoline plants, gas gathering systems, natural gas processing plants, pipeline systems and salt water disposal systems and costs incurred in installing pressure maintenance and secondary or tertiary production projects.

(dd) ***"Subscription Agreement"*** refers to the form of Limited Partner Subscription Agreement and Suitability Statement attached as Attachment I to the Partnership Agreement.

(ee) A ***"Substituted Limited Partner"*** is a transferee, donee, heir, legatee or other recipient of all or any portion of a Limited Partner's interest in the Partnership with respect to whom all conditions and consents required to become a Substituted Limited Partner under Article XIII of the Partnership Agreement have been satisfied and given.

(ff) A ***"Unit"*** is a preformation unit of limited partnership interest of a Limited Partner in the Partnership representing a Capital Subscription of One Thousand Dollars ($1,000).

FINANCIAL STATEMENTS

Unit Petroleum Company functions as the operating entity for all oil and natural gas exploration and production activities including operating any partnerships for UNIT.

The consolidated balance sheet of Unit Petroleum Company at October 31, 2006 is unaudited and includes all adjustments which UNIT considers necessary for a fair presentation of the financial position of Unit Petroleum Company at October 31, 2006.

Unit Petroleum Company
Consolidated Balance Sheet
(In Thousands)

	October 31, 2006 (Unaudited)
Assets	
Current Assets:	
Cash and cash equivalents	$ 641
Trade accounts receivable	24,790
Materials and supplies, at lower of cost or market	19,460
Other	603
Total current assets	45,494
Property and Equipment:	
Oil and natural gas properties, on the full cost method	1,258,769
Other	806
	1,259,575
Less accumulated depreciation, depletion, amortization and impairment	440,809
Net property and equipment	818,766
Other Assets	45
Total Assets	$ 864,305
Liabilities and Shareholders' Equity	
Current Liabilities:	
Current portion of long-term liabilities	645
Accounts payable	17,264
Accounts payable to parent	115,300
Contract advances	7,758
Accrued liabilities	7,989
Total current liabilities	148,956

Other Long-Term Liabilities	32,414
Deferred Income Taxes	205,306
Shareholders' Equity:	
Common stock, $1.00 par value, 500 shares authorized and outstanding	1
Capital in excess of par value	31,543
Retained earnings	446,085
Total shareholders' Equity	477,629
Total Liabilities and Shareholders' Equity	$ 864,305

EXHIBIT A

UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP

AGREEMENT OF LIMITED PARTNERSHIP

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UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP
AGREEMENT OF LIMITED PARTNERSHIP

THIS AGREEMENT OF LIMITED PARTNERSHIP (this **"Agreement"**) is made and entered into by and among Unit Petroleum Company, an Oklahoma corporation, hereinafter referred to as the **"General Partner"** or **"UPC"** (which term shall include any successors or assigns of UPC), and each of those persons who have executed a counterpart of the Limited Partner Subscription Agreement and Suitability Statement attached as Attachment I to this Agreement that have been accepted by the General Partner, said persons being hereinafter collectively referred to as the **"Limited Partners."**

WITNESSETH THAT:

ARTICLE I
Formation of Limited Partnership

1.1 The parties to this Agreement hereby form a Limited Partnership (the **"Partnership"**) pursuant to the Revised Uniform Limited Partnership Act of the State of Oklahoma (the **"Act"**). The terms and provisions hereof will be construed and interpreted in accordance with the terms and provisions of the Act and if any of the terms and provisions of this Agreement should be deemed inconsistent with those terms and provisions of the Act which under the Act may not be altered by agreement of the parties, the Act will be controlling, but otherwise this Agreement will be controlling.

1.2 The Partnership will be conducted under the name of "Unit 2007 Employee Oil and Gas Limited Partnership" in Oklahoma, and under such name or variations of such name as the General Partner deems appropriate to comply with the laws of the other jurisdictions in which the Partnership does business.

1.3 The principal office of the Partnership will be 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136, or at such other location as may from time to time be designated by the General Partner, and the Partnership's agent for service of process shall be Unit Corporation (**"UNIT,"** which term shall include all or any of its subsidiaries or affiliates unless the context otherwise requires) at the same address.

1.4 The Partnership will be effective on the date on which the certificate evidencing formation of the Partnership is filed with the Secretary of State of the State of Oklahoma. Its business and operations will not be commenced prior to such date. The Partnership will continue in existence until December 31, 2037, unless sooner terminated pursuant to any provisions of this Agreement.

1.5 The parties hereto will execute such certificates and other documents, and the General Partner will file, record and publish such certificates and documents, as may be necessary or appropriate to comply with the requirements for the formation and operation of a limited partnership under the Act and as the General Partner, upon advice of counsel, deems necessary or appropriate to comply with requirements of applicable laws governing the formation and operations of a limited partnership (or a partnership in which special partners have a limited liability) in all other jurisdictions where the Partnership desires to conduct business, including, but not limited to, filings under the Fictitious Name Act, Assumed Name Act or similar law in effect in the counties, parishes and other governmental jurisdictions in which the Partnership conducts business. The General Partner shall not be required to deliver or mail a copy of the certificate of limited partnership or any amendments thereto filed pursuant to the Act to the Limited Partners.

1.6 Each Limited Partner by his or her execution of a counterpart of the Subscription Agreement irrevocably constitutes and appoints the General Partner such Limited Partner's true and lawful attorney and agent, with full power and authority in such Limited Partner's name, place and stead, to execute, sign, acknowledge, swear to, deliver, file and record in the appropriate public offices (i) all certificates or other instruments (including, without limitation, counterparts of this Agreement) and amendments thereto which the General Partner deems appropriate to qualify or continue the Partnership as a limited partnership (or a partnership in which special partners have limited liability) in the jurisdictions in which the Partnership conducts business; (ii) all instruments and amendments thereto which the General Partner deems appropriate to reflect any change or modification of this Agreement, the admission of additional or substitute Partners in accordance with the terms of this Agreement, the release or waiver of the Limited Partners from the obligation to pay in one or more of the installments of their Capital Subscriptions pursuant to Section 4.2 below and the termination of the Partnership and the cancellation of the certificate of limited partnership; (iii) all conveyances and other instruments which the General Partner deems appropriate to evidence and reflect any sales or transfers, including sales or transfers upon or in connection with the dissolution and termination of the Partnership; and (iv) all consents to transfers of Partnership interests, to the admission of substitute or additional Partners or to the withdrawal or reduction of any Partner's invested capital, to the extent that such actions are authorized by the terms of this Agreement. The Power of Attorney granted herein is irrevocable and is a power coupled with an interest and will survive the death, disability, dissolution, bankruptcy, insolvency or incapacity of a Limited Partner.

ARTICLE II
Definitions

2.1 Whenever used in this Agreement the following terms will have the meanings described below:

(a) The **"*Additional Assessments*"** of the Limited Partners are those amounts, if any, which they are required to pay into the capital of the Partnership pursuant to Section 5.3 of this Agreement.

(b) An **"*affiliate*"** of another person is (1) any person directly or indirectly owning, controlling or holding with power to vote 10% or more of the outstanding voting securities of such other person; (2) any person 10% or more of whose outstanding voting securities are directly or indirectly owned, controlled, or held with power to vote, by such other person; (3) any person directly or indirectly controlling, controlled by, or under common control with such other person; (4) any officer, director, trustee or partner of such other person; and (5) if such other person is an officer, director, trustee or partner, any company for which such person acts in any such capacity.

(c) The **"*Aggregate Subscription*"** is the sum of the Capital Subscriptions of all Limited Partners.

(d) The **"*Capital Contribution*"** of a Limited Partner is the amount of the Capital Subscription actually paid in by him or her, or by any predecessor in interest, to the capital of the Partnership, including any payments made by deductions from salary. The "Capital Contribution" of the General Partner includes the amounts contributed to the Partnership or paid by the General Partner or by any Limited Partner whose Units are purchased by the General Partner including purchases pursuant to Section 4.2 of this Agreement because of a default by such Limited Partner in the payment of a subscription installment or pursuant to Article XV of this Agreement, including payments made by deductions from the salary of such Limited Partner.

(e) The **"*Capital Subscription*"** of a Limited Partner or his or her assignee (including the General Partner where Units are transferred pursuant to Section 4.2 of this Agreement) is the amount specified in the Subscription Agreement executed by such Limited Partner for payment by him or her to the capital of the Partnership in accordance with the provisions of this Agreement, reduced by the amount thereof from which the Limited Partner has been released by the General Partner of his or her obligation to pay pursuant to Section 4.2 hereof.

(f) ***"Drilling Costs"*** are those costs incurred in drilling, testing, completing and equipping a Partnership Well to the point that it proves to be dry and is abandoned or is ready to commence commercial production of oil or gas therefrom.

(g) ***"Effective Date"*** refers to the date on which the certificate evidencing formation of the Partnership is filed with the Secretary of State of the State of Oklahoma as required by the Act (54 Okla. Stat. 2001, Section 309).

(h) A ***"farm-out"*** is an agreement whereby the owner of an oil and gas property agrees to assign such property, usually retaining some interest therein such as an overriding royalty, a production payment, a net profits interest or a carried working interest, subject in most cases, however, to the drilling of one or more wells or other performance by the prospective assignee as a condition of the assignment.

(i) The ***"General Partner's Minimum Capital Contribution"*** is that amount equal to the total of (i) all Partnership costs and expenses charged to its account from the time of the formation of the Partnership through December 31, 2007, plus (ii) the General Partner's estimate of the total Leasehold Acquisition Costs and Drilling Costs expected to be incurred by the Partnership subsequent to December 31, 2007, minus (iii) the amount, if any, of the unexpended Aggregate Subscription at December 31, 2007.

(j) The ***"General Partner's Percentage"*** is that percentage determined by dividing the amount of the General Partner's Minimum Capital Contribution by the total of (i) the General Partner's Minimum Capital Contribution plus (ii) the Aggregate Subscription.

(k) ***"Leasehold Acquisition Costs"*** with respect to properties, if any, acquired by the Partnership from non-affiliated parties mean the actual costs to the Partnership of and in acquiring the properties, and, with respect to properties acquired by the Partnership from the General Partner, UNIT or its affiliates, are, without duplication, the sum of: (1) the prices paid by the General Partner, UNIT or its affiliates in acquiring an oil and gas property, including purchase option fees and charges, bonuses and penalties, if any; (2) title insurance or examination costs, broker's commissions, filing fees, recording costs, transfer taxes, if any, and like charges incurred in connection with the acquisition of such property; (3) a pro rata portion of the actual, necessary and reasonable expenses of the General Partner, UNIT or its affiliates for seismic and geophysical services; (4) rentals, shut-in royalties and ad valorem taxes paid by the General Partner, UNIT or its affiliates with respect to such property to the date of its transfer to the Partnership; (5) interest and points actually incurred on funds used by the General Partner, UNIT or its affiliates to acquire or maintain such property; and (6) such portion of the General Partner's, UNIT's or its affiliates' reasonable, necessary and actual expenses for geological, engineering, drafting, accounting, legal and other like services allocated to the acquisition, operations and maintenance of the property in accordance with generally accepted industry practices, except for expenses in connection with the past drilling of wells which are not producers of sufficient quantities of oil or gas to make commercially reasonable their continued operations, and provided that the costs and expenses enumerated in (4), (5) and (6) above with respect to any particular property shall have been incurred not more than thirty-six (36) months prior to the acquisition of such property by the Partnership. In the event a fractional undivided interest in a property is sold or transferred by the General Partner, UNIT or any affiliate to an unaffiliated third party for an amount in excess of that portion of the original cost of the property attributable to the transferred interest, the amount of such excess shall not reduce or be offset against the amount of the Leasehold Acquisition Costs attributable to any interest in the same property which is transferred to the Partnership.

(l) ***"Limited Partners"*** are those persons who acquire Units in the Partnership upon its formation and those transferees of Units who are accepted as Substituted Limited Partners. The General Partner may also be a Limited Partner if it subscribes for Units or if it subsequently acquires Units by (i) the exercise by a Limited Partner of his or her right of presentment; (ii) a purchase by the General Partner of the Units of a Limited Partner who defaults in the payment of any subscription installment; or (iii) any other assignment or transfer.

(m) The **"*Limited Partners' Percentage*"** is that percentage determined by dividing the amount of the Aggregate Subscription by the total of (i) the General Partner's Minimum Capital Contribution plus (ii) the Aggregate Subscription.

(n) **"*Normal Retirement*"** means retirement under the provision of a pension or similar retirement plan adopted by the General Partner, UNIT or any subsidiary with whom a Limited Partner is employed as in effect at the time of the employee's retirement.

(o) **"*Oil and gas properties*"** are oil and gas leasehold working interests, fee interests, mineral interests, royalty interests, overriding royalty interests, production payments, options or rights to lease or acquire such interests, geophysical exploration permits and any tangible or intangible properties or other rights incident thereto, whether real, personal or mixed.

(p) **"*Operating Expenses*"** are expenditures made and costs incurred in producing and marketing oil or gas from completed wells, including, in addition to labor, fuel, repairs, hauling, material, supplies, utility charges and other costs incident to or necessary for the maintenance or operation of such wells or the marketing of production therefrom, ad valorem, severance and other such taxes (other than windfall profit taxes), insurance and casualty loss expense and compensation to well operators or others for services rendered in conducting such operations.

(q) The General Partner and the Limited Partners are sometimes collectively referred to as the **"*Partners.*"**

(r) The **"*Partnership Properties*"** are oil and gas properties or interests therein acquired by the Partnership or properties acquired by any partnership or joint venture in which the Partnership is a partner or joint venturer, whether acquired by purchase, option exercise or otherwise.

(s) **"*Partnership Revenue*"** refers to the Partnership's gross revenues from all sources, including interest income, proceeds from sales of production, the Partnership's share of revenues from partnerships or joint ventures of which it is a member, sales or other dispositions of Partnership Properties or other Partnership assets, provided that contributions to Partnership capital by the Partners and the proceeds of any Partnership borrowings are specifically excluded and dry-hole and bottom-hole contributions shall be treated as reductions of the costs giving rise to the right to receive such contributions.

(t) **"*Partnership Wells*"** are any and all of the oil and gas wells in which the Partnership has an interest, either directly or indirectly through any other partnership or joint venture.

(u) **"*Productive properties*"** are oil and gas properties that have been tested by drilling and determined to be capable of producing oil or gas in commercial quantities.

(v) **"*Special Production and Marketing Costs*"** are costs and expenses that are not normally and customarily incurred in connection with drilling, producing and marketing operations, including without limitation, costs incurred in constructing compressor plants, gasoline plants, gas gathering systems, natural gas processing plants, pipeline systems and salt water disposal systems and costs incurred in installing pressure maintenance and secondary or tertiary production projects.

(w) **"*Subscription Agreement*"** refers to the form of Limited Partner Subscription Agreement and Suitability Statement attached as Attachment I to this Agreement.

(x) A **"*Substituted Limited Partner*"** is a transferee, donee, heir, legatee or other recipient of all or any portion of a Limited Partner's interest in the Partnership with respect to whom all conditions and consents required to become a Substituted Limited Partner under Article XIII have been satisfied and given.

(y) A **"*Unit*"** is a preformation unit of limited partnership interest of a Limited Partner in the Partnership representing a Capital Subscription of One Thousand Dollars ($1,000).

ARTICLE III
Purposes and Powers of the Partnership

3.1 The purposes of the Partnership will be to acquire productive oil and gas properties and to explore for, produce, treat, transport and market oil, gas or both, or products derived therefrom, anywhere in the United States. It is contemplated that all or most of the Partnership's operations will be conducted as part of the operations of the General Partner and its affiliates, but the Partnership may engage in operations on its own or in conjunction with unaffiliated third parties. In accomplishing such purposes the Partnership may:

(a) acquire oil and gas properties, either alone or in conjunction with other parties;

(b) conduct geological and geophysical investigations, including, without limitation, seismic exploration, core drilling and other means and methods of exploration;

(c) drill, equip, complete, rework, reequip, recomplete, plug back, deepen, plug and abandon Partnership Wells as the General Partner deems advisable;

(d) acquire and dispose of tangible lease and well equipment for use or used in connection with Partnership Wells;

(e) employ or retain such personnel and obtain such legal, accounting, geological, geophysical, engineering and other professional services and advice as the General Partner may deem advisable in the course of the Partnership's operations under this Agreement;

(f) either pay or elect not to pay delay rentals or shut-in royalties on Partnership Properties as appropriate in the judgment of the General Partner, it being understood that the General Partner will not be liable for failure to make correct or timely payments of delay rentals or shut-in royalties if such failure was due to any reason other than gross negligence or lack of good faith;

(g) make or give dry-hole or bottom-hole or other contributions of oil and gas properties, money or both, to encourage drilling by others in the vicinity of or on Partnership Properties;

(h) negotiate for and accept dry-hole, bottom-hole or other contributions of oil and gas properties, cash or both, as consideration for the drilling of a Partnership Well, with oil and gas properties so acquired, if any, to become Partnership Properties;

(i) pay all ad valorem taxes levied or assessed against the Partnership Properties, all taxes upon or measured by the production of oil or gas or other hydrocarbons therefrom, and all other taxes (other than income taxes) directly relating to operations conducted under this Agreement;

(j) enter into and operate pursuant to operating agreements with respect to Partnership Properties naming either the General Partner, any of its affiliates or a third party as operator, or enter into partnership agreements with third parties whereby the Partnership may be either a general or a limited partner (including any partnerships formed or sponsored by the General Partner or in which the General Partner may also be a partner), which operating or partnership agreements shall contain such terms, provisions and conditions as the General Partner deems appropriate;

(k) execute all documents or instruments of any kind which the General Partner deems appropriate for carrying out the purposes of the Partnership, including, without limitation, unitization agreements, gasoline plant contracts, recycling agreements and agreements relating to pressure maintenance and secondary or tertiary production projects;

(l) purchase and establish inventories of equipment and material required or expected to be required in connection with its operations;

(m) contract or enter into agreements with unaffiliated third parties, the General Partner or its affiliates for the performance of services and the purchase and sale of material, equipment, supplies and property, both real and personal, provided, however, that any such contracts or agreements with the General Partner or any of its affiliates shall, except as otherwise provided herein, provide for prices, fees, rates, charges or other compensation which are not greater than those available from, being paid to or charged by unaffiliated third parties dealing at arm’s length in the same or a similar geographic area for the same or comparable services, material, equipment, supplies or property;

(n) conduct operations either alone or as a joint venturer, co-tenant, partner or in any other manner of participation with third persons and to enter into agreements and contracts setting forth the terms and provisions of such participation;

(o) borrow money from banks and other lending institutions for Partnership purposes and pledge Partnership Properties (including production therefrom) for the repayment of such loans, it being understood that no bank or other lending institution to which the General Partner makes application for a loan will be required to inquire as to the purposes for which such loan is sought, and as between the Partnership and such bank or lending institution it will be conclusively presumed that the proceeds of such loan are to be and will be used for purposes authorized under the terms of this Agreement;

(p) hold Partnership Properties in its own name or in the name of the General Partner, UNIT or any affiliate or any other party as nominee for the Partnership;

(q) sell, relinquish, release, farm-out, abandon or otherwise dispose of Partnership Properties, including undeveloped, productive and condemned properties;

(r) produce, treat, transport and market oil and gas and execute division orders, contracts for the marketing or sale of oil, gas or other hydrocarbons and other marketing agreements;

(s) purchase, sell or pledge payments out of production from Partnership Properties; and

(t) perform any and all other acts or activities customary or incident to exploration for or development, production and marketing of oil and gas.

ARTICLE IV
Partner Capital Contributions

4.1 The General Partner will have the unrestricted right to admit such parties as Limited Partners as it deems advisable. By their execution of the Subscription Agreement, the Limited Partners severally agree, subject to the acceptance of their subscription by the General Partner, to be bound by the terms hereof as Limited Partners.

4.2 The Capital Subscriptions of the Limited Partners will be payable either (i) in four equal installments on March 15, 2007, June 15, 2007, September 15, 2007, and December 15, 2007, respectively, or (ii) by employees so electing, through equal deductions from 2007 salary paid to the employee by the General Partner, UNIT or its subsidiaries commencing immediately after the Effective Date. Notwithstanding the foregoing, if in the judgment of the General Partner, the entire amount of the Aggregate Subscription is not required for purposes of conducting the business, operations and affairs of the Partnership, the General Partner may, at its sole option, elect to release the Limited Partners from the obligation to pay in one or more of the installments of their Capital Subscriptions. If Units are acquired by a corporation or other entity, the beneficial owners of the interests therein shall be jointly and severally liable for the payment of the Capital Subscription. If an employee or director who has subscribed for Units (either directly or through a corporation or other entity) ceases to be employed by or a director of the General Partner, UNIT or any of its subsidiaries for any reason other than death, disability or Normal Retirement prior to the time the full amount of his or her Capital Subscription is paid, then the due date for any unpaid amount shall be accelerated so that the full amount of his or her unpaid Capital Subscription shall be due and payable on the effective date of such termination. The Capital Subscriptions shall be legally binding obligations of the Limited Partners and any past due amounts shall bear interest at the annual rate equal to two (2) percentage points in excess of the prime rate of interest of Bank of Oklahoma, N.A., Tulsa, Oklahoma, or successor bank, as announced and in effect from time to time, until paid. Further, in the event a Limited Partner fails to pay any installment when due, the General Partner, at its sole option and discretion, may elect to purchase the Units of such defaulting Limited Partner at a price equal to the total amount of the Capital Contributions actually paid into the Partnership by such defaulting Limited Partner, less the amount of any Partnership distributions that may have been received by him or her. Such option may be exercised by the General Partner by written notice to the Limited Partner at any time after the date that the unpaid installment was due and shall be deemed exercised when the amount of the purchase price is first tendered to the defaulting Limited Partner. The General Partner may, in its discretion, accept payments of delinquent installments but shall not be required to do so. In the event that the General Partner elects to purchase the Units of a defaulting Limited Partner, it shall pay into the Partnership the amount of the delinquent installment (excluding any interest that may have accrued thereon) and shall pay each additional installment, if any, payable with respect to such Units as it becomes due. By virtue of such purchase, the General Partner shall be allocated all Partnership Revenues and be charged with all Partnership costs and expenses attributable to such Units otherwise allocable or chargeable to the defaulting Limited Partner to the extent provided in Section 13.9.

4.3 If the Partnership requires funds to conduct Partnership operations during the period between any of the installments due as set forth in Section 4.2 above, then, notwithstanding the provisions of Section 5.4 below, the General Partner shall advance funds to the Partnership in an amount equal to the funds then required to conduct such operations but in no event more than the total amount of the Aggregate Subscription remaining unpaid. With respect to any such advances, the General Partner shall receive no interest thereon and no financing charges will be levied by the General Partner in connection therewith. The General Partner shall be repaid out of the Capital Subscription installments thereafter paid into the capital of the Partnership when due.

4.4 Additional Assessments required by the General Partner pursuant to Section 5.3 of this Agreement will be payable in cash on such date as the General Partner may set in its written notice, but in no event will such assessments be due earlier than thirty (30) days after the date of mailing of the notice. Notice of the General Partner’s call for Additional Assessments shall specify the amount required, the manner in which the additional funds will be expended, the date on which such amounts are payable, and the consequences of non-payment. The General Partner will not be required to accept late payments of such amounts, but it may in its discretion do so.

4.5 The General Partner will contribute to the capital of the Partnership amounts equal to the total of all costs paid by the Partnership that are charged to the General Partner's account as such costs are incurred.

ARTICLE V
Deposit and Use of Capital Contributions and Other Partnership Funds

5.1 Until required in the conduct of the Partnership's business, Partnership funds, including, but not limited to, Capital Contributions, Partnership Revenue and proceeds of borrowings by the Partnership, will be deposited, with or without interest, in one or more bank accounts of the Partnership in a bank or banks selected by the General Partner or invested in short-term United States government securities, money market funds, bank certificates of deposit or commercial paper rated as "A1" or "P1" as the General Partner, in its sole discretion, deems advisable. Any interest or other income generated by such deposits or investments will be for the Partnership's account. Except for Capital Contributions, Partnership funds from any of the various sources mentioned above may be commingled with other Partnership funds and with the funds of the General Partner and may be withdrawn, expended and distributed as authorized by the terms and provisions of this Agreement.

5.2 The Capital Contributions of the Limited Partners will be expended for costs incurred by the Partnership that, in accordance with the terms of this Agreement, are properly chargeable to the Limited Partners' accounts.

5.3 After the General Partner's Minimum Capital Contribution has been fully expended, if the Aggregate Subscription has all been fully expended or committed and additional funds are required in order to pay Drilling Costs, Special Production and Marketing Costs or Leasehold Acquisition Costs of productive properties which are chargeable to the Limited Partners, the General Partner may, but shall not be required to, make one or more calls for Additional Assessments from Limited Partners pursuant to Section 4.4; provided, however, that the aggregate amount of Additional Assessments called of the Limited Partners may not exceed $100 per Unit. The Limited Partners who do not respond will participate in production, if any, obtained from the aggregate Additional Assessments paid into the Partnership. However, the amount of the unpaid Additional Assessment shall bear interest at the annual rate equal to two (2) percentage points in excess of the prime rate of interest of Bank of Oklahoma, N.A., Tulsa, Oklahoma, or successor bank, as announced and in effect from time to time, until paid. The Partnership will have a lien on the defaulting Limited Partner's interest in the Partnership and the General Partner may apply Partnership Revenue otherwise available for distribution to the defaulting Limited Partner until an amount equal to the unpaid Additional Assessment and interest is received. Furthermore, the General Partner may satisfy such lien by proceeding with legal action to enforce the lien and the defaulting Limited Partner shall pay all expenses of collection, including interest, court costs and a reasonable attorney's fee.

5.4 After the General Partner's Minimum Capital Contribution has been fully expended, the General Partner may cause the Partnership to borrow funds for the purpose of paying Drilling Costs, Special Production and Marketing Costs or Leasehold Acquisition Costs of productive properties, which borrowings may be secured by interests in the Partnership Properties and will be repaid, including interest accruing thereon, out of Partnership Revenue allocable to the accounts of the Partners on whose behalf the proceeds of such borrowings are expended. The General Partner may, but is not required to, advance funds to the Partnership for the same purposes for which Partnership borrowings are authorized by this Section 5.4. With respect to any such advances, the General Partner shall receive interest in an amount equal to the lesser of the interest which would be charged to the Partnership by unrelated banks on comparable loans for the same purpose or the General Partner's interest cost with respect to such loan, where it borrows the same. No financing charges will be levied by the General Partner in connection with any such loan. If Partnership borrowings secured by interests in the Partnership Properties and repayable out of Partnership Revenue cannot be arranged on a basis which, in the opinion of the General Partner, is fair and reasonable, and the entire sum required to pay costs of the type referred to above is not available from Partnership Revenue, the Partnership may elect not to drill or participate in the drilling of a well or the General Partner may dispose of the Partnership Properties upon which such operations were to be conducted by sale (subject to any other applicable provisions of this Agreement), farm-out or abandonment.

5.5 The General Partner may utilize Partnership Revenue allocable to the respective accounts of the Partners to pay any Partnership costs and expenses properly chargeable to the accounts of such Partners.

5.6 With respect to any Partnership activity and subject to the restrictions set forth in Sections 5.3 and 5.4 above, it shall be in the sole discretion of the General Partner whether to call for Additional Assessments, arrange for borrowings on behalf of the Partners, utilize Partnership Revenue or sell (subject to any other applicable provisions of this Agreement), farm-out or abandon Partnership Properties.

5.7 The Partnership Properties and production therefrom may be pledged, mortgaged or otherwise encumbered as security for borrowings by the Partnership authorized by Section 5.4 above, provided that the holder of indebtedness arising by virtue of such borrowings may not have or acquire, at any time as a result of making any such loans, any direct or indirect interest in the profits, capital or property of the Partnership other than as a secured creditor.

ARTICLE VI
Sharing of Costs, Capital Accounts and Allocation of Charges and Income

6.1 All costs of organizing the Partnership and offering Units therein will be paid by the General Partner. All costs incurred in the offering and syndication of any drilling or income program formed by UPC or UNIT and its affiliates during 2007 in which the Partnership participates as a co-general partner will also be paid by the General Partner.

6.2 All other Partnership costs and expenses will be charged 99% to the accounts of the Limited Partners and 1% to the account of the General Partner until such time as the Aggregate Subscription has been fully expended. Thereafter and until the General Partner’s Minimum Capital Contribution has been fully expended, all of such costs and expenses will be charged to the General Partner. After the General Partner’s Minimum Capital Contribution has been fully expended, such costs and expenses will be charged to the respective accounts of the General Partner and the Limited Partners on the basis of their respective Percentages.

6.3 All Partnership Revenues will be allocated between the General Partner and the Limited Partners on the basis of their respective Percentages.

6.4 Partnership costs, expenses and Revenues which are charged and allocated to the Limited Partners shall be charged and allocated to their respective accounts in the proportion the Units of each Limited Partner bear to the total number of outstanding Units.

6.5 Capital accounts shall be established and maintained for each Partner in accordance with tax accounting principles and with valid regulations issued by the U.S. Treasury Department under subsection 704(b) (the "704 Regulations") of the Internal Revenue Code of 1986, as amended (the "Code"). To the extent that tax accounting principles and the 704 Regulations may conflict, the latter shall control. In connection with the establishment and maintenance of such capital accounts, the following provisions shall apply:

(a) Each Partner's capital account shall be (i) increased by the amount of money contributed by him or her to the Partnership, the fair market value of property contributed by him or her to the Partnership (net of liabilities securing such contributed property that the Partnership is considered to assume or take subject to under section 752 of the Code) and allocations to him or her of Partnership income and gain (except to the extent such income or gain has previously been reflected in his or her capital account by adjustments thereto) and (ii) decreased by the amount of money distributed to him or her by the Partnership, the fair market value of property distributed to him or her by the Partnership (net of liabilities securing such distributed property that such Partner is considered to assume or take subject to under section 752 of the Code) and allocations to him or her of Partnership loss, deduction (except to the extent such loss or deduction has previously been reflected in his or her capital account by adjustments thereto) and expenditures described in section 705(a)(2)(B) of the Code.

(b) In the event Partnership Property is distributed to a Partner, then, before the capital account of such Partner is adjusted as required by subsection (a) of this Section 6.5, the capital accounts of the Partners shall be adjusted to reflect the manner in which the unrealized income, gain, loss and deduction inherent in such property (that has not been reflected in such capital accounts previously) would be allocated among the Partners if there were a taxable disposition of such property for its fair market value on the date of distribution.

(c) If, pursuant to this Agreement, Partnership Property is reflected on the books of the Partnership at a book value that differs from the adjusted tax basis of such property, then the Partners' capital accounts shall be adjusted in accordance with the 704 Regulations for allocations to the Partners of depreciation, depletion, amortization, and gain or loss, as computed for book purposes, with respect to such property.

(d) The Partners' capital accounts shall be adjusted for depletion and gain or loss with respect to the Partnership's oil or gas properties in whichever of the following manners the General Partner determines is in the best interests of the Partners:

(i) the Partners' capital accounts shall be reduced by a simulated depletion allowance computed on each oil or gas property using either the cost depletion method or the percentage depletion method (without regard to the limitations under the Code which could apply to less than all Partners); provided, however, that the choice between the cost depletion method and the simulated depletion method shall be made on a property-by-property basis in the first taxable year of the Partnership for which such choice is relevant for an oil or gas property, and such choice shall be binding for all Partnership taxable years during which such oil or gas property is held by the Partnership. Such reductions for depletion shall not exceed the aggregate adjusted basis allocated to the Partners with respect to such oil or gas property. Such reductions for depletion shall be allocated among the Partners' capital accounts in the same proportions as the adjusted basis in the particular property is allocated to each Partner. Upon the taxable disposition of an oil or gas property by the Partnership, the Partnership's simulated gain or loss shall be determined by subtracting its simulated adjusted basis (aggregate adjusted tax basis of the Partners less simulated depletion allowances) in such property from the amount realized on such disposition and the Partners' capital accounts shall be increased or reduced, as the case may be, by the amount of the simulated gain or loss on such disposition in proportion to the Partners' allocable shares of the total amount realized on such disposition, or

(ii) the Partnership shall reduce the capital account of each Partner in an amount equal to such Partner's depletion allowance with respect to each oil or gas property of the Partnership (for the Partner's taxable year that ends within the Partnership's taxable year), but such reductions for depletion shall not exceed the adjusted basis allocated to such

Partner with respect to such property. Upon the taxable disposition of an oil or gas property by the Partnership, the capital account of each Partner shall be reduced or increased, as the case may be, by the amount of the difference between such Partner's allocable share of the total amount realized on such disposition and such Partner's remaining adjusted tax basis in such property.

(e) For purposes of determining the capital account balance of any Partner as of the end of any Partnership taxable year for purposes of Subsection 6.6(f) hereof, such Partner's capital account shall be reduced by:

(i) adjustments that, as of the end of such year, reasonably are expected to be made to such Partner's capital account pursuant to paragraph (b)(2)(iv)(k) of the 704 Regulations for depletion allowances with respect to oil and gas properties of the Partnership,

(ii) allocations of loss and deduction that, as of the end of such year, reasonably are expected to be made to such Partner pursuant to Code section 704(e)(2), Code section 706(d), and paragraph (b)(2)(ii) of section 1.751-1 of regulations promulgated under the Code, and

(iii) distributions that, as of the end of such year, reasonably are expected to be made to such Partner to the extent they exceed offsetting increases to such Partner's capital account that reasonably are expected to occur during (or prior to) the Partnership taxable years in which such distributions reasonably are expected to be made.

6.6 With respect to the various allocations of Partnership income, gain, loss, deduction and credit for federal income tax purposes, it is hereby agreed as follows:

(a) To the extent permitted by law, all charges, deductions and losses shall be allocated for federal income tax purposes in the same manner as the costs in respect of which such charges, deductions and losses are charged to the respective accounts of the Partners. The Partners bearing the costs shall be entitled to the deductions (including, without limitation, cost recovery allowances, depreciation and cost depletion) and credits that are attributable to such costs.

(b) The Partnership shall allocate to each Partner his or her portion of the adjusted basis in each depletable Partnership Property as required by Section 613A(c)(7)(D) of the Code based upon the interest of said Partner in the capital of the Partnership as of the time of the acquisition of such Partnership Property. To the extent permitted by the Code, such allocation shall be based upon said Partner's interest (i) in the Partnership capital used to acquire the property, or (ii) in the adjusted basis of the property if it is contributed to the Partnership. If such allocation of basis is not permitted under the Code, then basis will be allocated in the permissible manner which the General Partner deems will most closely achieve the result intended above.

(c) Partnership Revenue shall be allocated for federal income tax purposes in the same manner as it is allocated to the respective accounts of the Partners pursuant to Sections 6.3 and 6.4 above.

(d) Depreciation or cost recovery allowance recapture and recapture of intangible drilling and development costs, if any, due as a result of sales or dispositions of assets shall be allocated in the same proportion that the depreciation, cost recovery allowances or intangible drilling and development costs being recaptured were allocated.

(e) Notwithstanding anything to the contrary stated herein,

(i) there shall be allocated first to other Limited Partners and then to the General Partner any item of loss, deduction, credit or allowance that, but for this Subsection 6.6(e), would have been allocated to any Limited Partner that is not obligated to restore any deficit balance in such Limited Partner's capital account and would have thereupon caused or increased a deficit balance in such Limited Partner's capital account as of the end of the Partnership's taxable year to which such allocation related (after taking into consideration the numbered items specified in Subsection 6.5(e) hereof);

(ii) any Limited Partner that is not obligated to restore any deficit balance in such Limited Partner's capital account who unexpectedly receives an adjustment, allocation or distribution specified in Subsection 6.5(e) hereof shall be allocated items of income and gain in an amount and manner sufficient to eliminate such deficit balance as quickly as possible; and

(iii) in the event any allocations of loss, deduction, credit or allowance are made to a Limited Partner or the General Partner pursuant to clause (i) of this Subsection 6.6(e), then such Limited Partner and/or the General Partner shall be subsequently allocated all items of income and gain pro rata as they were allocated the item(s) of loss, deduction, credit or allowance under such clause (i) until the aggregate amount of such allocations of income and gain is equal to the aggregate amount of any such allocations of loss, deduction, credit or allowance allocated to such Partner(s) pursuant to clause (i) of this Subsection 6.6(e).

(f) Notwithstanding any other provision of this Agreement, if, under any provision of this Agreement, the capital account of any Partner is adjusted to reflect the difference between the basis to the Partnership of Partnership Property and such property's fair market value, then all items of income, gain, loss and deduction with respect to such property shall be allocated among the Partners so as to take account of the variation between the basis of such property and its fair market value at the time of the adjustment to such Partner's capital account in accordance with the requirements of subsection 704(c) of the Code, or in the same manner as provided under subsection 704(c) of the Code.

6.7 Notwithstanding anything to the contrary that may be expressed or implied in this Agreement, the interest of the General Partner in each material item of Partnership income, gain, loss, deduction or credit shall be equal to at least one percent of each such item at all times during the existence of the Partnership. In determining the General Partner's interest in such items, Units owned by the General Partner shall not be taken into account.

6.8 Except as provided in subsections (a) through (d) of this Section 6.8, in the case of a change in a Partner's interest in the Partnership during a taxable year of the Partnership, all Partnership income, gain, loss, deduction or credit allocable to the Partners shall be allocated to the persons who were Partners during the period to which such item is attributable in accordance with the Partners' interests in the Partnership during such period regardless of when such item is paid or received by the Partnership.

(a) With respect to certain "allocable cash basis items" (as such term is defined in the Code) of Partnership Revenue, gain, loss, deduction or credit, if, during any taxable year of the Partnership there is change in any Partner's interest in the Partnership, then, except to the extent provided in regulations prescribed under Section 706 of the Code, each Partner's allocable share of any "allocable cash basis item" shall be determined by (i) assigning the appropriate portion of each such item to each day in the period to which it is attributable, and (ii) allocating the portion assigned to any such day among the Partners in proportion to their interests in the Partnership at the close of such day.

(b) If, by adhering to the method of allocation described in the immediately preceding subsection of this Section 6.8, a portion of any "allocable cash basis item" is attributable to any period before the beginning of the Partnership taxable year in which such item is received or paid, such portion shall be (i) assigned to the first day of the taxable year in which it is received or paid, and (ii) allocated among the persons who were Partners in the Partnership during the period to which such portion is attributable in accordance with their interests in the Partnership during such period.

(c) If any portion of any "allocable cash basis item" paid or received by the Partnership in a taxable year is attributable to a period after the close of that taxable year, such portion shall be (i) assigned to the last day of the taxable year in which it is paid or received, and (ii) allocated among the persons who are Partners in proportion to their interests in the Partnership at the close of such day.

(d) If any deduction is allocated to a person with respect to an "allocable cash basis item" attributable to a period before the beginning of the Partnership taxable year and such person is not a Partner of the Partnership on the first day of the Partnership taxable year, such deduction shall be capitalized by the Partnership and treated in the manner provided for in Section 755 of the Code.

ARTICLE VII
Fiscal Year, Accountings and Reports

7.1 Unless the Code requires otherwise, the fiscal year of the Partnership will be the calendar year and the books of the Partnership will be kept in accordance with usual and customary accounting practices on the accrual method.

7.2 Within sixty (60) days after the end of each quarter of each Partnership fiscal year, each person who was a Limited Partner during such period will be furnished a report setting forth the source and disposition of Partnership funds during the quarter.

7.3 Not later than the end of the fiscal year in which all Partnership Wells are drilled and completed, and sufficient production history has been obtained on Partnership Wells to evaluate properly the reserves attributable thereto, the General Partner will make an evaluation of Partnership Properties as of the last day of such fiscal year. The report shall include an estimate of the total oil and gas proven reserves of the Partnership and the dollar value thereof and the value of the Limited Partner's interest in such reserve value. It shall also contain an estimate of the present worth of the reserves. Each Limited Partner will receive a summary statement of such report reflecting the Limited Partners' interest in such reserve value.

ARTICLE VIII
Tax Returns and Elections

8.1 Unless the Code requires otherwise, the General Partner will cause the Partnership to elect the calendar year as its taxable year and will timely file all Partnership income tax returns required to be filed by the jurisdictions in which the Partnership conducts business or derives income. By March 15 of each year or as soon thereafter as practicable, the General Partner will furnish all available information necessary for inclusion in the income tax returns of each person who was a Limited Partner during the prior fiscal year. The General Partner shall be the "Tax Matters Partner" for the Partnership pursuant to the provisions of Section 6231 of the Code subject to the provisions of Section 10.22 below.

8.2 The Partnership will elect to deduct intangible drilling and development costs currently as an expense for income tax purposes and will elect to use the available depreciation method which, in the General Partner's judgment, is in the best interest of the Partners.

8.3 The General Partner shall have the right in its sole discretion at any time to make or not to make such other elections as are authorized or permitted by any law or regulation for income tax purposes (including any election under Section 754 of the Code).

ARTICLE IX
Distributions

9.1 The Partnership's available cash will be distributed to the Limited Partners and the General Partner in the same proportions that Partnership Revenue has been allocated to them after giving effect to previous distributions and to portions of such revenue theretofore used or retained to pay costs incurred or expected to be incurred in conducting Partnership operations or to repay borrowings theretofore or expected to be thereafter obtained by the Partnership. Within forty-five (45) days after the end of each calendar quarter, the General Partner will determine the amount of cash available for distribution to the Limited Partners and will distribute such amount, if any, as promptly thereafter as reasonably possible. Distributions of cash to the General Partner may be at any time the General Partner determines there is cash available therefor. The General Partner's determination of the cash available for distribution will be conclusive and binding upon all Partners. All Partnership funds distributed to the Limited Partners shall be distributed to the persons who were record holders of Units on the day on which the distribution is made.

ARTICLE X
Rights, Duties and Obligations of the General Partner

10.1 Subject to the limitations of this Agreement, the General Partner will have full, exclusive and complete discretion in the management and control of the business of the Partnership and will make all decisions affecting its business and affairs or the Partnership Properties. The General Partner will have, subject to the provisions of this Article X, full power and authority to take any action described in Article III above and execute and deliver in the name of and on behalf of the Partnership such documents or instruments as the General Partner deems appropriate for the conduct of Partnership business. No person, firm or corporation dealing with the Partnership will be required to inquire into the authority of the General Partner to take any action or make any decision.

10.2 The General Partner will perform the duties imposed upon it under this Agreement in an efficient and businesslike manner with due caution and in accordance with established practices of the oil and gas industry, but the General Partner shall not be liable, responsible or accountable in damages or otherwise to the Partnership or any of the Partners for, and the Partnership shall indemnify, defend against and save harmless the General Partner, from any expense (including attorneys' fees), loss or damage incurred by reason of any act or omission performed or omitted in good faith on behalf of the Partnership or the Partners, and in a manner reasonably believed by the General Partner to be within the scope of the authority granted by this Agreement and in the best interests of the Partnership or the Partners, provided that the General Partner is not guilty of gross negligence or willful misconduct with respect to such acts or omissions, and further provided that the satisfaction of any indemnification and any saving harmless shall be from and limited to Partnership assets including insurance proceeds, if any, and no Partner shall have any personal liability on account thereof. For purposes of this Section 10.2 only, the term General Partner includes the General Partner, affiliates of the General Partner and any officer, director or employee of the General Partner or any of its affiliates such that all of such parties are covered by the indemnities provided herein.

10.3 The General Partner will utilize its organization and employees and will hire outside consultants for the Partnership as necessary in order to provide experienced, qualified and competent personnel to conduct the Partnership's business. With certain limited exceptions it is the intent of the Partners that the Partnership participate as a co-general partner of any oil and gas drilling or income programs, or both, formed by the General Partner or UNIT for third party investors during 2007 and to participate on a proportionate working interest basis in each producing oil and gas lease acquired and in the drilling of each oil and gas well commenced by the General Partner or UNIT for its own account during the period from the later of January 1, 2007 or the Effective Date through December 31, 2007 (except for wells, if any, (i) drilled outside of the 48 contiguous United States; (ii) drilled as part of secondary or tertiary recovery operations which were in existence prior to the formation of the Partnership; (iii) drilled by third parties under farm-out or similar arrangements with the General Partner or UNIT or whereby the General Partner or UNIT may be entitled to an overriding royalty, reversionary or other similar interest in the production from such wells but is not obligated to pay any of the Drilling Costs thereof; (iv) acquired by UNIT or the General Partner through the acquisition by UNIT or the General Partner of, or merger of UNIT or the General Partner with, other companies; or (v) with respect to which the General Partner does not believe that the potential economic return therefrom justifies the costs of participation by the Partnership).

10.4 The General Partner, UNIT or any affiliate thereof will transfer to the Partnership interests in oil and gas properties comprising the spacing unit on which a Partnership Well is located or is to be drilled for the separate account of the Partnership, provided that no broker's commissions or fees of a similar nature will be paid in connection with any such transfer and the consideration paid by the Partnership will be equal to the Leasehold Acquisition Costs of the property so transferred. If the size of a spacing unit on which a Partnership Well is located is ever reduced or increased well density is permitted thereon, the Partnership will not be entitled to any reimbursement or recoupment of any portion of the Leasehold Acquisition Costs paid with respect thereto notwithstanding the provisions of Section 10.7 below.

10.5 With respect to certain transactions involving Partnership Properties, it is hereby agreed as follows:

(a) A sale, transfer or conveyance by the General Partner or any affiliate of less than its entire interest in such property is prohibited unless (i) the interest retained by the General Partner or its affiliate is a proportionate working interest, (ii) the respective obligations of the General Partner or its affiliate and the Partnership are substantially the same proportionately as those of the General Partner or its affiliate at the time it acquired the property and (iii) the Partnership's interest in revenues will not be less than the proportionate interest therein of the General Partner or its affiliate when it acquired the property. The General Partner or its affiliate may retain the remaining interest for its own account or it may sell, transfer, farm-out or otherwise convey all or a portion of such remaining interest to non-affiliated industry members. In connection with any such sale, transfer, farm-out or other conveyance of such interest to non-affiliated industry members, which may occur either before or after the transfer of the interests in the same properties to the Partnership, the General Partner or its affiliate may realize a profit on the interests or may be carried to some extent with respect to its cost obligations in connection with any drilling on such properties and any such profit or interest will be strictly for the account of the General Partner and the Partnership will have no claim with respect thereto.

(b) The General Partner or its affiliates may not retain any overrides or other burdens on property conveyed to the Partnership (other than overriding royalty interests granted to geologists and other persons employed or retained by the General Partner or its affiliates).

10.6 The General Partner will cause the Partnership Properties to be acquired in accordance with the customs of the oil and gas industry in the area. The Partnership will be required to do only such title work with respect to its oil and gas properties as the General Partner in its sole judgment deems appropriate in light of the area, any applicable drilling or expiration dates and any other material factors.

10.7 Partnership Properties shall be transferred to the Partnership after the decision to acquire a productive property or the commitment to drill a Partnership Well thereon has been made. The Partnership shall acquire interests in only those properties of the General Partner or UNIT which comprise the spacing unit on which the Partnership Well is drilled or on which a producing Partnership Well is located. If a spacing unit on which a Partnership Well is drilled or located is ever reduced, or any subsequent well in which the Partnership has no interest is drilled thereon, the Partnership will have no interest in any such subsequent or additional wells drilled on properties which were a part of the original spacing unit unless any such additional well is commenced during 2007 or is drilled by a drilling or income program of which the Partnership is a partner. Likewise if UNIT, UPC or any affiliate, including any oil and gas partnership subsequently formed for investment or participation by employees, directors and/or consultants of UNIT or any of its subsidiaries, acquires additional interests in Partnership Wells after 2007 the Partnership generally will not be entitled to participate in the acquisition of such additional interests. In addition, if a Partnership Well drilled on a spacing unit is dry or abandoned, the Partnership will not have an interest in any subsequent or additional well drilled on the spacing unit unless it is commenced during 2007 or is drilled by a drilling or income program of which the Partnership is a partner.

10.8 The General Partner, UNIT or its affiliates will either conduct the Partnership's drilling and production operations and operate each Partnership Well or arrange for a third party operator to conduct such operations. The General Partner will, on behalf of the Partnership, enter into appropriate operating agreements with other owners of Partnership Wells authorizing the General Partner, its affiliates or a third party operator to conduct such operations. The Partnership will take such action in connection with operations pursuant to said operating agreements as the General Partner, in its sole discretion, deems appropriate and in the best interests of the Partnership, and the decision of the General Partner with respect thereto will be binding upon the Partnership.

10.9 The General Partner will cause the Partnership to plug and abandon its dry holes and abandoned wells in accordance with rules and regulations of the governmental regulatory body having jurisdiction.

10.10 The General Partner may pool or unitize Partnership Properties with other oil and gas properties when such pooling or unitization is required by a governmental regulatory body, when well spacing as determined by any such body requires such pooling or unitization, or when, in the General Partner's opinion, such pooling or unitization is in the best interests of the Partnership.

10.11 The General Partner will have authority to make and enter into contracts for the sale of the Partnership's share of oil or gas production from Partnership Wells, including contracts for the sale of such production to the General Partner, UNIT or its affiliates; provided, however, that the production purchased by the General Partner, UNIT or any of its affiliates will be for prices which are not less than the highest posted price (in the case of crude oil production) or prevailing price (in the case of natural gas production) in the same field or area.

10.12 The General Partner will use its best efforts to procure and maintain for the Partnership, and at its expense, such insurance coverage with responsible companies as may be reasonably available for such premium costs as would not be considered to be unreasonably high or prohibitive with respect to each item of coverage and as the General Partner considers necessary for the protection of the Partnership and the Partners. The coverage will be in such amounts and will cover such risks as the General Partner believes warranted by the operations conducted hereunder. Such risks may include but will not necessarily be limited to public liability and automobile liability, each covering bodily injury, death and property damage, workmen's compensation and employer's liability insurance and blowout and control of well insurance.

10.13 In order to conduct properly the business of the Partnership, and in order to keep the Partners properly informed, the General Partner will:

(a) maintain adequate records and files identifying the Partnership Properties and containing all pertinent information in regard thereto that is obtained or developed pursuant to this Agreement;

(b) maintain a complete and accurate record of the acquisition and disposition of each Partnership Property;

(c) maintain appropriate books and records reflecting the Partnership's revenue and expense and each Partner's participation therein;

(d) maintain a capital account for each Partner with appropriate records as necessary in order to reflect each Partner's interest in the Partnership and furnish required tax information; and

(e) keep the Limited Partners informed by means of written reports on the acquisition of Partnership Properties and the progress of the business and operations of the Partnership, which reports will be rendered semi-annually and at such more frequent intervals during the progress of Partnership operations as the General Partner deems appropriate.

10.14 The General Partner, UNIT and the officers, directors, employees and affiliates thereof may own, purchase or otherwise acquire and deal in oil and gas properties, drill wells, conduct operations and otherwise engage in any aspect of the oil and gas business, either for their own accounts or for the accounts of others. Each Limited Partner hereby agrees that engaging in any activity permitted by this Section 10.14 will not be considered a breach of any duty that the General Partner, UNIT or the officers, directors, employees and affiliates thereof may have to the Partnership or the Limited Partners, and that the Partnership and the Limited Partners will not have any interest in any properties acquired or profits which may be realized with respect to any such activity.

10.15 Subject to Section 12.1, without the prior consent of Limited Partners holding a majority of the outstanding Units, the General Partner will not (i) make, execute or deliver any assignment for the benefit of the Partnership's creditors; or (ii) contract to sell all or substantially all of the Partnership Properties (except as permitted by Sections 10.23 and 16.4(b)).

10.16 In contracting for services to and insurance coverage for the Partnership and its activities and operations, and in acquiring material, equipment and personal property on behalf of the Partnership, the General Partner will use its best efforts to obtain such services, insurance, material, equipment and personal property at prices no less favorable than those normally charged in the same or in comparable geographic areas by non-affiliated persons or companies dealing at arm's length. No rebates, concessions or compensation of a similar nature will be paid to the General Partner by the person or company supplying such services, insurance, material, equipment and personal property.

10.17 The General Partner, UNIT or its affiliates are authorized to provide equipment, materials and services to the Partnership in connection with the conduct of its operations, provided, that the terms of any contracts between the Partnership and the General Partner, UNIT or any affiliates, or the officers, directors, employees and affiliates thereof must be no less favorable to the Partnership than those of comparable contracts entered into, and will be at prices not in excess of those charged in the same geographical area by non-affiliated persons or companies dealing at arm's length. Any such contracts for services must be in writing precisely describing the services to be rendered and all compensation to be paid.

10.18 The General Partner may cause the Partnership to hold Partnership Properties in the Partnership's name, or in the name of the General Partner, UNIT, any affiliates thereof or some third party as nominee for the Partnership. If record title to a Partnership Property is to be held permanently in the name of a nominee, such nominee arrangement will be evidenced and documented by a nominee agreement identifying the Partnership Properties so held and disclaiming any beneficial interest therein by the nominee.

10.19 The General Partner will be generally liable for the debts and obligations of the Partnership, provided that any claims against the Partnership shall be satisfied first out of the assets of the Partnership and only thereafter out of the separate assets of the General Partner.

10.20 The Partnership may not make any loans to the General Partner, UNIT or any of its affiliates.

10.21 The General Partner will use its best efforts at all times to maintain its net worth at a level that is sufficient to insure that the Partnership will be classified for federal income tax purposes as a partnership, rather than as an association taxable as a corporation, on account of the net worth of the General Partner.

10.22 The Tax Matters Partner designated in Section 8.1 above is authorized to engage legal counsel and accountants and to incur expense on behalf of the Partnership in contesting, challenging and defending against any audits, assessments and administrative or judicial proceedings conducted or participated in by the Internal Revenue Service with respect to the Partnership's operations and affairs.

10.23 At any time two years or more after the Partnership has completed substantially all of its property acquisition, drilling and development operations, the General Partner may, without the vote, consent or approval of the Limited Partners, cause all or substantially all of the oil and gas properties and other assets of the Partnership to be sold, assigned or transferred to, or the Partnership merged or consolidated with, another partnership or a corporation, trust or other entity for the purpose of combining the assets of two or more of the oil and gas partnerships formed for investment or participation by employees, directors and/or consultants of UNIT or any of its subsidiaries; provided, however, that the valuation of the oil and gas properties and other assets of all such participating partnerships for purposes of such transfer or combination shall be made on a consistent basis and in a manner which the General Partner and UNIT believe is fair and equitable to the Limited Partners. As a consequence of any such transfer or combination, the Partnership shall be dissolved and terminated pursuant to Article XVI hereof and the Limited Partners shall receive partnership interests, stock or other equity interests in the transferee or resulting entity.

ARTICLE XI
Compensation and Reimbursements

11.1 For the General Partner's services performed as operator of productive Partnership Wells located on Partnership Properties and as operator during the drilling of Partnership Wells, the Partnership will compensate the General Partner at rates no higher than those normally charged in the same or a comparable geographic area by non-affiliated persons or companies dealing at arm's length. The General Partner will not receive compensation for such services performed in connection with the operation of Partnership Wells operated by third party operators, but such third party operators will be compensated as provided in the operating agreements in effect with respect to such wells and the Partnership will pay its proportionate share of such compensation.

11.2 The General Partner will be reimbursed by the Partnership out of Partnership Revenues for that portion of its general and administrative overhead expense that is attributable to its conduct of the actual and necessary business, affairs and operations of the Partnership. The General Partner's general and administrative overhead expenses will be determined in accordance with industry practices. The allocable costs and expenses will include all customary and routine legal, accounting, geological, engineering, travel, office rent, telephone, secretarial, salaries, data processing, word processing and other incidental reasonable expenses necessary to the conduct of the Partnership's business and generated by the General Partner or allocated to it by UNIT, but will not include filing fees, commissions, professional fees, printing costs and other expenses incurred in forming the Partnership or offering interests therein. Also excluded will be any general and administrative overhead expense of the General Partner or UNIT which may be attributable to its services as an operator of Partnership Wells for which it receives compensation pursuant to Section 11.1 above. The portion of the General Partner's general and administrative overhead expense to be reimbursed by the Partnership with respect to any particular period will be determined by allocating to the Partnership that portion of the General Partner's total general and administrative overhead expense incurred during such period which is equal to the ratio of the Partnership's total expenditures compared to the total expenditures by the General Partner for its own account. The portion of such general and administrative overhead expense reimbursement which is charged to the Limited Partners may not exceed an amount equal to 3% of the Aggregate Subscription during the first 12 months of the Partnership's operations, and in each succeeding twelve-month period, the lesser of (a) 2% of the Aggregate Subscription and (b) 10% of the total Partnership Revenue realized in such twelve-month period. Administrative expenses incurred directly by the Partnership, or incurred by the General Partner on behalf of the Partnership and reimbursable to the General Partner, such as legal, accounting, auditing, reporting, engineering, mailing and other such fees, costs and expenses are not to be deemed a part of the general and administrative expense of the General Partner which is to be reimbursed pursuant to this Section 11.2 and the amounts thereof will not be subject to the limitations described in the preceding sentence.

ARTICLE XII
Rights and Obligations of Limited Partners

12.1 The Limited Partners, in their capacity as such, cannot transact any business for the Partnership or take part in the control of its business or management of its affairs. Limited Partners will have no power to execute any agreements on behalf of, or otherwise bind or commit, the Partnership. They may give consents and approvals as herein provided and exercise the rights and powers granted to them in this Agreement, it being understood that the exercise of such rights and powers will be deemed to be matters affecting the basic structure of the Partnership and not the exercise of control over its business; provided, however, that exercise of any of the rights and powers granted to the Limited Partners in Sections 10.15, 12.3, 14.1, 16.1 and 18.1 will not be authorized or effective unless prior to the exercise thereof the General Partner is furnished an opinion of counsel for the Partnership or an order or judgment of any court of competent jurisdiction to the effect that the exercise of such rights or powers (i) will not be deemed to evidence that the Limited Partners are taking part in the control of or management of the Partnership's business and affairs, (ii) will not result in the loss of any Limited Partner's limited liability and (iii) will not result in the Partnership being classified as an association taxable as a corporation or a publicly traded partnership for federal income tax purposes.

12.2 The Limited Partners will not be personally liable for any debts or losses of the Partnership. Except as otherwise specifically provided herein, no Partner will be responsible for losses of any other Partners.

12.3 Except as otherwise provided in this Agreement, no Limited Partner will be entitled to the return of his contribution. Distributions of Partnership assets pursuant to this Agreement may be considered and treated as returns of contributions if so designated by law or, subject to Section 12.1, by agreement of the General Partner and Limited Partners holding a majority of the outstanding Units. The value of a Limited Partner's undistributed contribution determined for the purposes of Section 39 of the Act at any point in time shall be his or her percentage of the amount of the Partnership's stated capital allocated to the Limited Partners as reflected in the financial statements of the Partnership as of such point in time. No Partner will receive any interest on his or her contributions and no Partner will have any priority over any other Partner as to the return of contributions.

ARTICLE XIII
Transferability of Limited Partner's Interest

13.1 Notwithstanding the provisions of Section 13.3, no sale, exchange, transfer or assignment of a Limited Partner's interest in the Partnership may be made unless in the opinion of counsel for the Partnership,

(a) such sale, exchange, transfer or assignment, when added to the total of all other sales, exchanges, transfers or assignments of interests in the Partnership within the preceding 12 months, would not result in the Partnership being considered to have terminated within the meaning of Section 708 of the Code (provided, however, that this condition may be waived by the General Partner in its discretion);

(b) such sale, exchange, transfer or assignment would not violate, or cause the offering of the Units to be violative of, the Securities Act of 1933, as amended, or any state securities or "blue sky" laws (including any investor suitability standards) applicable to the Partnership or the interest to be sold, exchanged, transferred or assigned; and

(c) such sale, exchange, transfer or assignment would not cause the Partnership to lose its status as a partnership for federal income tax purposes, and said opinion of counsel is delivered in writing to the Partnership prior to the date of the sale, exchange, transfer or assignment.

13.2 In no event shall all or any part of an interest in the Partnership be assigned or transferred to a minor (except in trust or pursuant to the Uniform Transfers to Minors Act) or an incompetent (except in trust), except by will or intestate succession.

13.3 Except for transfers or assignments (in trust or otherwise) by a Limited Partner of all or any part of his or her interest in the Partnership

(a) to the General Partner,

(b) to or for the benefit of himself or herself, his or her spouse, or other members of his or her immediate family sharing the same household,

(c) to a corporation or other entity in which all of the beneficial owners are Limited Partners or assigns permitted in (a) and (b) above, or

(d) by the General Partner to any person who at the time of such transfer is an employee of the General Partner, UNIT or its subsidiaries,

no Limited Partner's Units or any portion thereof may be sold, assigned or transferred except by reason of death or operation of law.

13.4 If a Limited Partner dies, his or her executor, administrator or trustee, or, if he or she is adjudicated incompetent, his or her committee, guardian or conservator, or, if he or she becomes bankrupt, the trustee or receiver of his or her estate, shall have all the rights of a Limited Partner for the purpose of settling or managing his or her estate and such power as the deceased, incapacitated or bankrupt Limited Partner possessed to assign all or any part of his or her interest and to join with such assignee in satisfying conditions precedent to such assignee's becoming a Substituted Limited Partner.

13.5 The Partnership shall not recognize for any purpose any purported sale, assignment or transfer of all or any fraction of the interest of a Limited Partner in the Partnership, unless the provisions of Section 13.1 shall have been complied with and there shall have been filed with the Partnership a written and dated notification of such sale, assignment or transfer in form satisfactory to the General Partner, executed and acknowledged by both the seller, assignor or transferor and the purchaser, assignee or transferee and such notification (i) contains the acceptance by the purchaser, assignee or transferee of all of the terms and provisions of this Agreement and (ii) represents that such sale, assignment or transfer was made in accordance with all applicable laws and regulations. Any sale, assignment or transfer shall be recognized by the Partnership as effective on the date of such notification if the date of such notification is within thirty (30) days of the date on which such notification is filed with the Partnership, and otherwise shall be recognized as effective on the date such notification is filed with the Partnership.

13.6 Any Limited Partner who shall assign all of his or her interest in the Partnership shall cease to be a Limited Partner, except that, unless and until a Substituted Limited Partner is admitted in his or her stead, such assigning Limited Partner shall retain the statutory rights of the assignor of a Limited Partner's interest under the Act.

13.7 A person who is the assignee of all or any fraction of the interest of a Limited Partner, but does not become a Substituted Limited Partner and desires to make a further assignment of such interest, shall be subject to all the provisions of this Article XIII to the same extent and in the same manner as any Limited Partner desiring to make an assignment of his or her interest.

13.8 No Limited Partner shall have the right to substitute a purchaser, assignee, transferee, donee, heir, legatee, distributee or other recipient of all or any portion of such Limited Partner's interest in the Partnership as a Limited Partner in his or her place. Any such purchaser, assignee, transferee, donee, legatee, distributee or other recipient of an interest in the Partnership shall be admitted to the Partnership as a Substituted Limited Partner only with the consent of the General Partner, which consent shall be granted or withheld in the sole and absolute discretion of the General Partner and may be arbitrarily withheld, and only by an amendment to this Agreement or the certificate of limited partnership duly executed and recorded in the proper records of each jurisdiction in which the Partnership owns mineral interests and filed in the proper records of the State of Oklahoma. Any such consent by the General Partner shall be binding and conclusive without the consent of any Limited Partners and may be evidenced by the execution of the General Partner of an amendment to this Agreement or the certificate of limited partnership, evidencing the admission of such person as a Substituted Limited Partner.

13.9 No person shall become a Substituted Limited Partner until such person shall have:

(a) become a party to, and adopted all of the terms and conditions of, this Agreement;

(b) if such person is a corporation, partnership or trust, provided the General Partner with evidence satisfactory to counsel for the Partnership of such person's authority to become a Limited Partner under the terms and provisions of this Agreement; and

(c) paid or agreed to pay the costs and expenses incurred by the Partnership in connection with such person's becoming a Limited Partner.

Provided, however, that for the purpose of allocating Partnership Revenue, costs and expenses, a person shall be treated as having become, and as appearing in the records of the Partnership as, a Substituted Limited Partner on such date as the sale, assignment or transfer was recognized by the Partnership pursuant to Section 13.5.

13.10 By his or her execution of his or her Subscription Agreement, each Limited Partner represents and warrants to the General Partner and to the Partnership that his or her acquisition of his or her interest in the Partnership is made as principal for his or her own account for investment purposes only and not with a view to the resale or distribution of such interest. Each Limited Partner agrees that he or she will not sell, assign or otherwise transfer his or her interest in the Partnership or any fraction thereof unless such interest has been registered under the Securities Act of 1933, as amended, or such sale, assignment or transfer is exempt from such registration and, in any event, he or she will not so sell, assign or otherwise transfer his or her interest or any fraction thereof to any person who does not similarly represent, warrant and agree.

ARTICLE XIV
Assignments by the General Partner

14.1 The General Partner may not sell, assign, transfer or otherwise dispose of its interest in the Partnership except with the prior consent, subject to Section 12.1, of Limited Partners holding a majority of the outstanding Units; provided that a sale, assignment or transfer may be effective without such consent if pursuant to a bona fide merger, any other corporate reorganization or a complete liquidation, pursuant to a sale of all or substantially all of the General Partner's assets (provided the purchasers of such assets agree to assume the duties and obligations of the General Partner) or a sale or transfer to UNIT or any affiliates of UNIT. If the Limited Partners' consent to a proposed transfer is required, the General Partner will, concurrently with the request for such consent, give the Limited Partners written notice identifying the interest to be transferred, the date on which the transfer is to be effective, the proposed transferee and the substitute General Partner, if any.

14.2 Sales, assignments and transfers of the interests in the Partnership owned by the General Partner will be subject to, and the assignee will acquire the assigned interest subject to, all of the terms and provisions of this Agreement.

14.3 If the Limited Partners' consent to a transfer of the General Partner's interest in the Partnership is obtained as above provided, or is not required, the transferee may become a substitute General Partner hereunder. The substitute General Partner will assume and agree to perform all of the General Partner's duties and obligations hereunder and the transferring General Partner will, upon making a proper accounting to the substitute General Partner, be relieved of any further duties or obligations hereunder with respect to Partnership operations thereafter occurring.

ARTICLE XV
Limited Partners' Right of Presentment

15.1 After December 31, 2008, each Limited Partner will have the option, subject to the terms and conditions set forth in this Article XV, to require the General Partner to purchase all (but not less than all) of his or her Units, provided that the option may not be exercised after the date of any notice that will effect a dissolution and termination of the Partnership pursuant to Article XVI below. Any such exercise shall be effected by written notice thereof delivered to the General Partner.

15.2 Sales of Limited Partners' Units pursuant to this Article XV will be effective, and the purchase price for such interests will be determined, as of the close of business on the last day of the calendar year in which the Limited Partner's notice exercising his or her option is given, or, at the General Partner's election, as of 7:00 o'clock A.M. on the following day.

15.3 The purchase price to be paid for the Units of any Limited Partner who exercises the option granted in this Article XV will be determined in the following manner. First, future gross revenues expected to be derived from the production and sale of the proved reserves attributable to Partnership Properties will be estimated, as of the end of the calendar year in which presentment is made, by the independent engineering firm preparing a report on the reserves of the Partnership, or if no such firm is preparing a report as of the end of the calendar year in which the option is exercised, then by the General Partner. Next, future net revenues will be calculated by deducting anticipated expenses (including Operating Expenses and other costs that will be incurred in producing and marketing such reserves and any gross production, excise, or other taxes, other than federal income taxes, based on the oil and gas production of the Partnership or sales thereof) from estimated future gross revenues. The price to be used in calculating future gross revenues as well as the estimates of price and cost escalations to be used in such calculations will be those of such independent engineering firm or the General Partner, whichever is making the determination. Then the present worth of the future net revenues will be calculated by discounting the estimated future net revenues at that rate per annum which is one (1) percentage point higher than the prime rate of interest being charged by Bank of Oklahoma, N.A., Tulsa, Oklahoma, or any successor bank, as such prime rate of interest is announced by said bank as of the date such reserves are estimated. This amount will be reduced by an additional 25% to take into account the uncertainties attendant to the production and sale of oil and gas reserves and other unforeseen contingencies. Estimated salvage value of tangible equipment installed on the Partnership Wells and costs of plugging and abandoning the productive Partnership Wells, both discounted at the aforementioned rate from the expected date of abandonment, will be considered, and Partnership Properties, if any, which do not have proved reserves attributable to them but which have not been condemned will be valued at the lower of cost or their then current market value as determined by the aforementioned independent petroleum engineering firm or General Partner, as the case may be. The Partnership's cash on hand, prepaid expenses, accounts receivable (less a reasonable reserve for doubtful accounts) and the market value of its other assets as determined by the General Partner will be added to the value of the Partnership Properties thus determined, and the Partnership's debts, obligations and other liabilities will be deducted, to arrive at the Partnership's net asset value for purposes of this Section 15.3. The price to be paid for the Limited Partner's interest will be his or her proportionate share of such net asset value less 75% of the amount of any Partnership distributions received by him or her which are attributable to sales of Partnership production since the date as of which the Partnership's proved reserves are estimated.

15.4 Within one hundred twenty (120) days after the end of any calendar year in which a Limited Partner exercises his or her option to require purchase of his or her Units as provided in this Article XV, the General Partner will furnish to such Limited Partner a statement showing the price to be paid for his or her Units and evidencing that such price has been determined in accordance with the provisions of Section 15.3 above. The statement will show which portion of the proposed purchase price is represented by the value of the proved reserves and by each of the other classes of Partnership assets and liabilities attributable to the account of the Limited Partner. The Limited Partner will then have thirty (30) days to confirm, by further notice to the General Partner, his or her intention to sell his or her Units to the General Partner. If the Limited Partner timely confirms his or her intention to sell, the sale will be consummated and the price paid in cash within ten (10) days after such confirmation. The General Partner will not be obligated to purchase (i) any Units pursuant to such right if such purchase, when added to the total of all other sales, exchanges, transfers or assignments of the Units within the preceding 12 months, would result in the Partnership being considered to have terminated within the meaning of Section 708 of the Code, would cause the Partnership to lose its status as a partnership for federal income tax purposes, or would cause the Partnership to be treated as a publicly traded partnership for federal income tax purposes, or (ii) in any one calendar year more than 20% of the Units in the Partnership then outstanding. If less than all of the Units tendered are purchased, the interests purchased will be selected by lot. The Limited Partners whose tendered Units were rejected by reason of the foregoing limitation shall be entitled to priority in the following year. Contemporaneously with the closing of any such sale, the Limited Partner will execute such certificates or other documents and perform such acts as the General Partner deems necessary to effect the sale and transfer of the liquidating Limited Partner's Units to the General Partner and to preserve the limited liability status of the Partnership under the laws of the jurisdictions in which it is doing business.

15.5 As used in Sections 15.3 and 15.4 above, the term "proved reserves" shall have the meaning ascribed thereto in Regulation S-X adopted by the Securities and Exchange Commission.

ARTICLE XVI
Termination and Dissolution of Partnership

16.1 The Partnership will terminate automatically on December 31, 2037, unless prior thereto, subject to Section 12.1 above, the General Partner or Limited Partners holding a majority of the outstanding Units elect to terminate the Partnership as of an earlier date. In the event of such earlier termination, ninety (90) days' written notice will be given to all other Partners. The termination date will be specified in such notice and must be the last day of any calendar month following expiration of the ninety (90) day period unless an earlier date is approved by Limited Partners holding a majority of the outstanding Units.

16.2 Upon the dissolution (other than pursuant to a merger or other corporate reorganization), bankruptcy, legal disability or withdrawal of the General Partner (other than pursuant to Section 14.1 above), the Partnership shall immediately be dissolved and terminated; provided, however, that nothing in this Agreement shall impair, restrict or limit the rights and powers of the Partners under the laws of the State of Oklahoma and any other jurisdiction in which the Partnership is doing business to reform and reconstitute themselves as a limited partnership within ninety (90) days following the dissolution of the Partnership either under provisions identical to those set forth herein or under any other provisions. The withdrawal, expulsion, dissolution, death, legal disability, bankruptcy or insolvency of any Limited Partner will not effect a dissolution or termination of the Partnership.

16.3 Upon termination of the Partnership by action of the Limited Partners pursuant to Section 16.1 hereof or as a result of an event under Section 16.2 hereof, a party designated by the Limited Partners holding a majority of the outstanding Units will act as Liquidating Trustee. In any other case, the General Partner will act as Liquidating Trustee.

16.4 As soon as possible after December 31, 2037, or the date of the notice of or event causing an earlier termination of the Partnership, the Liquidating Trustee will begin to wind up the Partnership's business and affairs. In this regard:

(a) The Liquidating Trustee will furnish or obtain an accounting with respect to all Partnership accounts and the account of each Partner and with respect to the Partnership's assets and liabilities and its operations from the date of the last previous audit of the Partnership to the date of such dissolution;

(b) The Liquidating Trustee may, in its discretion, sell any or all productive and non-productive properties which, except in the case of an election by the General Partner to terminate the Partnership prior to the tenth anniversary of the Effective Date, may be sold to the General Partner or any of its affiliates for their fair market value as determined in good faith by the General Partner;

(c) The Liquidating Trustee shall:

(i) pay all of the Partnership's debts, liabilities and obligations to its creditors, including the General Partner; and

(ii) pay all expenses incurred in connection with the termination, liquidation and dissolution of the Partnership and distribution of its assets as herein provided;

(d) The Liquidating Trustee shall ascertain the fair market value by appraisal or other reasonable means of all assets of the Partnership remaining unsold, and each Partner's capital account shall be charged or credited, as the case may be, as if such property had been sold at such fair market value and the gain or loss realized thereby had been allocated to and among the Partners in accordance with Article VI hereof; and

(e) On or as soon as practicable after the effective date of the termination, all remaining cash and any other properties and assets of the Partnership not sold pursuant to the preceding subsections of this Section 16.4 will be distributed to the Partners (i) in proportion to and to the extent of any remaining balances in the Partners' capital accounts and then (ii) in undivided interests to the Partners in the same proportions that Partnership Revenues are being shared at the time of such termination, provided, that:

(i) the various interests distributed to the respective Partners will be distributed subject to such liens, encumbrances, restrictions, contracts, operating agreements, obligations, commitments or undertakings as existed with respect to such interests at the time they were acquired by the Partnership or were subsequently created or entered into by the Partnership;

(ii) if interests in the Partnership Wells that are not subject to any operating agreement are to be distributed, the Partners will, concurrently with the distribution, enter into standard form operating agreements covering the subsequent operation of each such well which will, if the termination is effected pursuant to Section 16.1 above, be in a form satisfactory to the General Partner and will name the General Partner or its designee as operator; and

(iii) no Partner shall be distributed an interest in any asset if the distribution would result in a deficit balance or increase the deficit balance in its capital account (after making the adjustments referred to in this Section 16.4 relating to distributions in kind).

16.5 If the General Partner has a deficit balance in its capital account following the distribution(s) provided for in Section 16.4(e) above, as determined after taking into account all adjustments to its capital account for the taxable year of the Partnership during which such distribution occurs, it shall restore the amount of such deficit balance to the Partnership within ninety (90) days and such amount shall be distributed to the other Partners in accordance with their positive capital account balances.

16.6 Notwithstanding anything to the contrary in this Agreement, upon the dissolution and termination of the Partnership, the General Partner will contribute to the Partnership the lesser of: (a) the deficit balance in its capital account; or (b) the excess of 1.01 percent of the total Capital Contributions of the Limited Partners over the capital previously contributed by the General Partner.

ARTICLE XVII
Notices

17.1 All notices, consents, requests, demands, offers, reports and other communications required or permitted shall be deemed to be given or made when personally delivered to the party entitled thereto, or when sent by United States mail in a sealed envelope, with postage prepaid, addressed, if to the General Partner, to 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136, and, if to a Limited Partner, to the address set forth below such Limited Partner's signature on the counterpart of the Subscription Agreement that he or she originally executed and delivered to the General Partner. The General Partner may change its address by giving notice to all Limited Partners. Limited Partners may change their address by giving notice to the General Partner.

ARTICLE XVIII
Amendments

18.1 Limited Partners do not have the right to propose amendments to this Agreement. The General Partner may propose an amendment or amendments to this Agreement by mailing to the Limited Partners a notice describing the proposed amendment and a form to be returned by the Limited Partners indicating whether they oppose or approve of its adoption. Such notice will include the text of the proposed amendment, which will have been approved in advance by counsel for the Partnership. If, within sixty (60) days, or such shorter period as may be designated by the General Partner, after any notice proposing an amendment or amendments to this Agreement has been mailed, Limited Partners holding a majority of the outstanding Units have properly executed and returned the form indicating that they approve of and consent to adoption of the proposed amendment, such amendment will become effective as of the date specified in such notice, provided that no amendment which alters the allocations specified in Article VI above, changes the compensation and reimbursement provisions set forth in Article XI above or is otherwise materially adverse to the interests of the Limited Partners will become effective unless approved by all Limited Partners. If an amendment does become effective, all Partners will promptly evidence such effectiveness by executing such certificates and other instruments as the General Partner may deem necessary or appropriate under the laws of the jurisdictions in which the Partnership is then doing business in order to reflect the amendment.

ARTICLE XIX
General Provisions

19.1 This Agreement embodies the entire understanding and agreement between the Partners concerning the Partnership, and supersedes any and all prior negotiations, understandings or agreements in regard thereto.

19.2 In those cases where this Agreement requires opinions to be expressed by, or actions to be approved by, counsel for Limited Partners, such counsel must be qualified and experienced in the fields of federal income taxation and partnership and securities laws.

19.3 This Agreement and the Subscription Agreement may be executed in multiple counterpart copies, each of which will be considered an original and all of which constitute one and the same instrument.

19.4 This Agreement will be deemed to have been executed and delivered in the State of Oklahoma and will be construed and interpreted according to the laws of that State.

19.5 This Agreement and all of the terms and provisions hereof will be binding upon and will inure to the benefit of the Partners and their respective heirs, executors, administrators, trustees, successors and assigns.

EXECUTED in the name of and on behalf of the undersigned General Partner this _______day of **January, 2007** but effective as of the Effective Date.

	"General Partner"
Attest:	UNIT PETROLEUM COMPANY
By ______________________________	By ______________________________
Mark E. Schell, Secretary	Larry D. Pinkston, President

LIMITED PARTNER SUBSCRIPTION AGREEMENT AND SUITABILITY STATEMENT

(ALL INFORMATION WILL BE TREATED CONFIDENTIALLY)

Unit 2007 Employee Oil and Gas Limited Partnership
c/o Unit Petroleum Company
7130 South Lewis Avenue, Suite 1000
Tulsa, Oklahoma 74136

MUST BE RECEIVED BY:
January 22, 2007

RETURN TO:
Unit 2007 Employee Oil and Gas
Limited Partnership
Attn: Mark Schell
7130 South Lewis Ave., Suite 1000
Tulsa, OK 74136

RE: Unit 2007 Employee Oil and
Gas Limited Partnership

Gentlemen:

In connection with the subscription of the undersigned for units of limited partnership interest (**"Units"**) in the Unit 2007 Employee Oil and Gas Limited Partnership (the **"Partnership"**) which the undersigned tenders herewith to Unit Petroleum Company (the **"General Partner"**), the undersigned is hereby furnishing the Partnership and the General Partner the information set forth herein below and makes the representations and warranties set forth below, to indicate whether the undersigned is a suitable subscriber for Units in the Partnership. As a condition precedent to investing in the Partnership, the undersigned hereby represents, warrants, covenants and agrees as follows:

1. The undersigned acknowledges that he or she has received and reviewed a copy of the Private Offering Memorandum (the **"Offering Memorandum"**) dated December 27, 2006 of the Unit 2007 Employee Oil and Gas Limited Partnership, relating to the offering of Units in the Partnership, and all Exhibits thereto, including the Agreement of Limited Partnership (the **"Agreement"**), and understands that the Units will be offered to others on the terms and in the manner described in the Offering Memorandum. The undersigned hereby subscribes for the number of Units set forth below pursuant to the terms of the Offering Memorandum and tenders his or her Capital Subscription as required and agrees to pay his or her Additional Assessments upon call or calls by the General Partner; and the undersigned acknowledges that he or she shall have the right to withdraw this subscription only up until the time the General Partner executes and accepts the undersigned's subscription and that the General Partner may reject any subscription for any reason without liability to it; and, further, the undersigned agrees to comply with the terms of the Agreement and to execute any and all further documents necessary in connection with his or her admission to the Partnership.

2. The undersigned has reviewed and acknowledges execution of the Power of Attorney set forth in the Agreement and elsewhere in this instrument.

3. The undersigned is aware that no federal or state regulatory agency has made any findings or determination as to the fairness for public or private investment, nor any recommendation or endorsement, of the purchase of Units as an investment.

4. The undersigned recognizes the speculative nature and risks of loss associated with oil and gas investments and that he or she may suffer a complete loss of his or her investment. The Units subscribed for hereby constitute an investment which is suitable and consistent with his or her investment program and that his or her financial situation enables him or her to bear the risks of this investment. The undersigned represents that he or she has adequate means of providing for his or her current needs and possible personal contingencies, and that he or she has no need for liquidity of this investment.

5. The undersigned confirms that he or she understands, and has fully considered for purposes of this investment, the RISK FACTORS set forth in the Offering Memorandum and that (i) the Units are speculative investments which involve a high degree of risk of loss by the undersigned of his or her investment therein, (ii) there is a risk that the anticipated tax benefits under the Agreement could be challenged by the Internal Revenue Service or could be affected by changes in the Internal Revenue Code of 1986, as amended, the regulations thereunder or administrative or judicial interpretations thereof thereby depriving Limited Partners of anticipated tax benefits, (iii) the General Partner and its affiliates will engage in transactions with the Partnership which may result in a profit and, in the future, may be engaged in businesses which are competitive with that of the Partnership, and the undersigned agrees and consents to such activities, even though there are conflicts of interest inherent therein, and (iv) there are substantial restrictions on the transferability of, and there will be no public market for, the Units and, accordingly, it may be difficult for him or her to liquidate his or her investment in the Units in case of emergency, if possible at all.

6. The undersigned confirms that in making his or her decision to purchase the Units subscribed for he or she has relied upon independent investigations made by him or her (or by his or her own professional tax and other advisors) and that he or she has been given the opportunity to examine all documents and to ask questions of, and to receive answers from the General Partner or any person(s) acting on its behalf concerning the terms and conditions of the offering or any other matter set forth in the Offering Memorandum, and to obtain any additional information, to the extent the General Partner possesses such information or can acquire it without unreasonable effort or expense, necessary to verify the accuracy of the information set forth in the Offering Memorandum, and that no representations have been made to him or her and no offering materials have been furnished to him or her concerning the Units, the Partnership, its business or prospects or other matters, except as set forth in the Offering Memorandum and the other materials described in the Offering Memorandum.

7. The undersigned understands that the Units are being offered and sold under an exemption from registration provided by Sections 3(b) and/or 4(2) of the Securities Act of 1933, as amended (the **"Act"**), and warrants and represents that any Units subscribed for are being acquired by the undersigned solely for his or her own account, for investment purposes only, and are not being purchased with a view to or for the resale, distribution, subdivision or fractionalization thereof; the undersigned has no agreement or other arrangement, formal or informal, with any person to sell, transfer or pledge any part of any Units subscribed for or which would guarantee the undersigned any rights to such Units; the undersigned has no plans to enter into any such agreement or arrangement, and, consequently, he or she must bear the economic

risk of the investment for an indefinite period of time because the Units cannot be resold or otherwise transferred unless subsequently registered under the Act (which neither the General Partner nor the Partnership is obligated to do), or an exemption from such registration is available and, in any event, unless transferred in compliance with the Agreement.

8. The undersigned further understands that the exemption under Rule 144 of the Act will not be generally available because of the conditions and limitations of such rule; that, in the absence of the availability of such rule, any disposition by him or her of any portion of his or her investment will require compliance under the Act; and that the Partnership and the General Partner are under no obligation to take any action in furtherance of making such exemption available.

9. The undersigned is aware that the General Partner will have full and complete control of Partnership operations and that he or she must depend on the General Partner to manage the Partnership profitably; and that a Limited Partner does not have the same rights as a stockholder in a corporation or the protection which stockholders might have, since limited partners have limited rights in determining policy.

10. The undersigned is aware that the General Partner will receive compensation for its services irrespective of the economic success of the Partnership.

11. The undersigned represents and warrants as follows (please mark and complete all applicable categories):

(a) If an individual, the undersigned is the sole party in interest, and the undersigned is at least 21 years of age and a bona fide resident and domiciliary (not a temporary or transient resident) of the state set forth opposite his or her signature hereto;

☐ YES ☐ NO

(b) If a partnership or corporation, the undersigned meets the following: (1) the entity has not been formed for the purposes of making this investment; (2) the entity was formed on ____________; and (3) the entity has a history of investments similar to the type described in the Offering Memorandum;

☐ YES ☐ NO

(c) The undersigned meets all suitability standards and acknowledges being aware of all legend conditions applicable to his or her state of residence as set forth herein;

☐ YES ☐ NO

(d)(i) The undersigned has a net worth (including home, furnishings and automobiles) of at least five times the amount of his or her Capital Subscription, and anticipates that he or she will have adjusted gross income during the current year in an amount which will enable him or her to bear the economic risks of the investment in the Partnership;

☐ YES ☐ NO

and

(ii) The undersigned is a salaried employee of Unit Corporation (**"UNIT"**) or one of its subsidiaries at the date of formation of the Partnership whose annual base salary for 2007 has been set at $36,000 or more, or the undersigned is a director of UNIT;

☐ YES ☐ NO

and

(e) The undersigned _______is or _______is not a citizen of the United States.

12. The undersigned represents and agrees that he or she has had sufficient opportunity to make inquiries of the General Partner in order to supplement information contained in the Offering Memorandum respecting the offering, and that any information so requested has been made available to his or her satisfaction, and he or she has had the opportunity to verify such information. The undersigned further agrees and represents that he or she has knowledge and experience in business and financial matters, and with respect to investments generally, and in particular, investments generally comparable to the offering, so as to enable him or her to utilize such information to evaluate the risks of this investment and to make an informed investment decision. The following is a brief description of the undersigned's experience in the evaluation of other investments generally comparable to the offering:

____

____

____

____

13. The undersigned is aware that the Partnership and the General Partner have been and are relying upon the representations and warranties set forth in this Limited Partner Subscription Agreement and Suitability Statement, in part, in determining whether the offering meets the conditions specified in Rules of the Securities and Exchange Commission and the exemption from registration provided by Sections 3(b) and/or 4(2) of the Act.

14. All of the information which the undersigned has furnished the General Partner herein or previously with respect to the undersigned's financial position and business experience is correct and complete as of the date of this Agreement, and, if there should be any material change in such information prior to the closing of the offering period of the Units, the undersigned will immediately furnish such revised or corrected information to the General Partner. The undersigned agrees that the foregoing representations and warranties shall survive his or her admission to the Partnership, as well as any acceptance or rejection of a subscription for the Units.

If the subscription tendered hereby of the undersigned is accepted by the General Partner, the undersigned hereby executes and swears to the Agreement of Limited Partnership of Unit 2007 Employee Oil and Gas Limited Partnership as a Limited Partner, thereby agreeing to all the terms thereof and duly appoints the General Partner, with full power of substitution, his or her true and lawful attorney to execute, file, swear to and record any Certificate of Limited Partnership or amendments thereto or cancellation thereof and any other instruments which may be required by law in any jurisdiction to permit qualification of the Partnership as a limited partnership or for any other purposes necessary to implement the Partnership's purposes.

THE SECURITIES REPRESENTED BY THIS CERTIFICATE HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED, THE OKLAHOMA SECURITIES ACT OR OTHER APPLICABLE STATE SECURITIES ACTS. THE SECURITIES HAVE BEEN ACQUIRED FOR INVESTMENT AND MAY NOT BE SOLD OR TRANSFERRED FOR VALUE IN THE ABSENCE OF AN EFFECTIVE REGISTRATION OF THEM UNDER THE SECURITIES ACT OF 1933, AS AMENDED, AND/OR THE OKLAHOMA SECURITIES ACT, OR ANY OTHER APPLICABLE ACT, OR AN OPINION OF COUNSEL TO UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP THAT SUCH REGISTRATION IS NOT REQUIRED UNDER SUCH ACT.

The undersigned hereby subscribes for _______Units (minimum subscription: 2 Units) at a price of $1,000 per Unit for a total Capital Subscription (as defined in Article II of the Agreement) of $___________, which shall be due and payable either:

(Check One)

☐ (a) in four equal installments on March 15, 2007, June 15, 2007, September 15, 2007 and December 15, 2007, respectively; or

☐ (b) through equal deductions from 2007 salary of the undersigned commencing immediately after the Effective Date (as defined in Article II of the Agreement).

LIMITED PARTNER:	RESIDENT ADDRESS:	
		(If placing Units in the name of spouse or trustee for minor child or children, please provide name, address of such spouse or trustee and Social Security or Tax Identification Number)
Signature		
Please Print Name	**Mailing Address** **<u>if different:</u>**	
Date:________________		**TAX I.D. OR SOCIAL** **<u>SECURITY NO.:</u>**

ACCEPTED THIS _______DAY OF January, 2007.

UNIT 2007 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP

By ______________________________

Authorized Officer of Unit
Petroleum Company, General Partner

Upon completion, an executed copy of this Limited Partner Subscription Agreement and Suitability Statement must be returned to ***<u>Unit 2007 Employee Oil and Gas Limited Partnership, Attention Mark E. Schell, 7130 South Lewis Avenue, Suite 1000, Tulsa, Oklahoma 74136</u>***. The General Partner, after acceptance, will return a copy of the accepted Subscription Agreement to the Limited Partner.

Conner & Winters, LLP
4000 One Williams Center
Tulsa, Oklahoma 74172-0148
918-586-5711
Fax 918-586-8982
www.cwlaw.com

Writer's Direct Number
918-586-8965
Writer's Fax Number
918-586-8665
Writer's E-mail Address
drather@cwlaw.com

January 3, 2007

Unit Petroleum Company
1000 Kensington Tower I
7130 South Lewis
Tulsa, Oklahoma 74136

Re: Unit 2007 Employee Oil and Gas Limited Partnership

Dear Sirs:

We have acted as counsel for Unit Petroleum Company, an Oklahoma corporation (the "General Partner"), which will be the General Partner in the Unit 2007 Employee Oil and Gas Limited Partnership, a proposed Oklahoma limited partnership (the "Partnership"). You have requested our opinions regarding certain federal income tax matters concerning the Partnership.

We have reviewed and relied upon the accuracy of the facts and information set forth in the Private Offering Memorandum dated December 15, 2006 (the "Memorandum"), covering the offer and sale of units of limited partnership interest ("Units") in the Partnership, the Agreement of Limited Partnership included as Exhibit A to the Memorandum (the "Partnership Agreement"), the consolidated balance sheet of the General Partner dated October 31, 2006, and such other documents and matters as we have considered necessary in order to render this opinion. Capitalized terms used herein have the meaning assigned to them in the Memorandum, except as otherwise specifically indicated.

In our examination we have assumed the authenticity of original documents, the accuracy of copies and the genuineness of signatures. We have relied upon the representations and statements of the General Partner of the Partnership with respect to the factual determinations underlying the legal conclusions set forth herein. We have not attempted to verify independently such representations and statements.

Please note that we are opining only as to the matters expressly set forth herein, and no opinion should be inferred as to any other matters. We are unable to render opinions as to a number of federal income tax issues relating to an investment in Units and the operations of the Partnership. Finally, we are not expressing any opinion with respect to the amount of allowable losses or credits that may be generated by the Partnership or the amount of each Partner's share of allowable losses or credits from the Partnership's activities.

The following opinion and statements are based upon the provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed regulations thereunder, current administrative rulings, and court decisions. The federal income tax law is uncertain as to many of the tax matters material to an investment in the Partnership, and it is not possible to predict with certainty how the law will develop or how the courts will decide various issues if they are litigated. While this opinion fairly states our views concerning the tax aspects of an investment in the Partnership, both the Internal Revenue Service (the "Service") and the courts may disagree with our position on certain issues.

Moreover, uncertainty exists concerning some of the federal income tax aspects of the transactions being undertaken by the Partnership. Some of the tax positions to be taken by the Partnership may be challenged by the Service and there is no assurance that any such challenge will not be successful. Thus, there can be no assurance that all of the anticipated tax benefits of an investment in the Partnership will be realized.

Our opinions are based upon the transactions described in the Memorandum (the "Transaction") and upon facts as they have been represented to us or determined by us as of the date of the opinion. Any alteration of the facts may adversely affect the opinions rendered. In our opinion, the preponderance of the material tax benefits, in the aggregate, will be realized by the Partners. It is possible, however, that some of the tax benefits will be eliminated or deferred to future years.

Because of the factual nature of the inquiry, and in certain cases the lack of clear authority in the law, it is not possible to reach a judgment as to the outcome on the merits (either favorable or unfavorable) of certain material federal income tax issues as described more fully herein.

Compliance with Circular 230

The United States Treasury Department establishes standards for tax practitioners who practice before the Internal Revenue Service (the "Service"). Those standards are set forth in a publication known as Circular 230. Circular 230 was recently revised and now requires that written statements issued by a tax practitioner that constitute a Covered Opinion, within the meaning of Circular 230, adhere to certain standards of factual and legal due diligence, contain certain material and conform to a specific manner of presentation.

We have concluded that this letter opinion (the "Letter") constitutes a Covered Opinion. Accordingly, the Letter is drafted in a manner designed to comply with the Covered Opinion requirements of Circular 230. We have concluded that no federal tax issue discussed in the Letter relates to a Listed Transaction within the meaning of Circular 230. We have concluded that the tax benefits discussed in the Letter likely are being claimed in accordance with provisions of the Code and the underlying Congressional purpose and, therefore, conclude that the principal purpose of the transactions as outlined are not tax avoidance. We have also concluded, however, that a significant purpose of the transactions may be tax avoidance, and, as set forth below, we have reached a more-likely-than-not conclusion (a greater than fifty percent (50%) likelihood) with respect to one or more significant federal tax issues that we discuss below. We have, therefore, concluded that the Letter constitutes a Reliance Opinion within the meaning of Circular 230.

Because we understand that you may use the Letter to promote, market, or recommend tax matters addressed herein, we also have concluded that this advice may be considered a Marketed Opinion within the meaning of Circular 230. However, the Letter is not intended to be a Marketed Opinion. Therefore, as permitted in Circular 230, we are providing the following Marketed Opinion disclaimer:

**IMPORTANT LIMITATIONS ON TAX ASPECTS —
MARKETED OPINION DISCLAIMER**

In order to avoid the characterization of the Letter constituting a Marketed Opinion, we state that this advice: (i) was not intended or written by the practitioner to be used and that it cannot be used by any taxpayer for the purpose of avoiding penalties; (ii) was written to support the promotion or marketing of the transaction or matters addressed by the written advice; and (iii) taxpayers should seek advice based on the taxpayer's particular circumstances from an independent tax advisor.

Circular 230 also provides that a Covered Opinion which is a Limited Scope Opinion, an opinion that is limited to the federal tax issues addressed in the opinion and which does not address all of the significant federal tax issues, satisfies the Covered Opinion requirements. The Letter is a Limited Scope Opinion. As required in Circular 230, therefore, we are providing the following Limited Scope Opinion disclosure:

**IMPORTANT LIMITATIONS ON TAX ASPECTS —
LIMITED SCOPE OPINION DISCLAIMER**

The Letter is limited to the United States federal income tax consequences addressed herein. Additional issues may exist that could affect the federal tax treatment of the transactions or matters addressed herein and the Letter does not *consider or provide a conclusion with respect to any such additional issues. The Letter was not written, and cannot be used, to avoid tax penalties with respect to any federal tax issues not addressed herein.*

SUMMARY OF CONCLUSIONS

Opinions expressed: The following is a summary of the specific opinions expressed by us with respect to the Federal Income Tax Considerations discussed herein. **TO BE FULLY UNDERSTOOD, THE COMPLETE DISCUSSION OF THESE MATTERS SHOULD BE READ BY EACH PROSPECTIVE PARTNER.**

1. The material federal income tax benefits in the aggregate from an investment in the Partnership will be realized.

2. The Partnership will be treated as a partnership for federal income tax purposes and not as a corporation, an association taxable as a corporation or a "publicly traded partnership."

3. To the extent the Partnership's wells are timely drilled and amounts are timely paid, the Partners will be entitled to their pro rata shares of the Partnership's IDC paid in 2007.

4. Limited Partners' interests will be considered a passive activity within the meaning of Code Section 469 and losses generated therefrom will be limited by the passive activity provisions of the Code.

5. To the extent provided herein, the Partners' distributive shares of Partnership tax items will be determined and allocated substantially in accordance with the terms of the Partnership Agreement.

6. The Partnership will not be required to register with the Service as a tax shelter.

No opinion expressed: Due to the lack of authority, or the essentially factual nature of the question, we express no opinion on the following:

1. The impact of an investment in the Partnership on an investor's alternative minimum tax liability.

2. Whether, under Code Section 183, the losses of the Partnership will be treated as derived from "activities not engaged in for profit," and therefore nondeductible from other gross income.

3. Whether each Partner will be entitled to percentage depletion since such a determination is dependent upon the status of the Partner as an independent producer.

4. Whether any interest incurred by a Partner with respect to any borrowings to acquire a Unit will be deductible or subject to limitations on deductibility.

5. Whether the Partnership will be treated as the tax owner of Partnership Properties acquired by the General Partner as nominee for the Partnership.

General Information: Certain matters contained herein are not considered to address a material tax consequence and are for general information, including the matters contained in sections dealing with gain or loss on the sale of Units or of property, Partnership distributions, tax audits, penalties, and state and local tax.

Our opinions are also based upon the facts described in the Memorandum and upon certain representations made to us by the General Partner for the purpose of permitting us to render our opinions, including the following representations with respect to the Partnership:

1. The Partnership Agreement to be entered into by and among the General Partner and Limited Partners and any amendments thereto will be duly executed and will be made available to any Limited Partner upon written request. The Partnership Agreement will be duly recorded in all places required under the Oklahoma Revised Uniform Limited Partnership Act (the "Act") for the due formation of the Partnership and for the continuation thereof in accordance with the terms of the Partnership Agreement. The Partnership will at all times be operated in accordance with the terms of the Partnership Agreement, the Memorandum, and the Act.

2. No election will be made by the Partnership, any of the Limited Partners, or the General Partner to be excluded from the application of the provisions of Subchapter K of the Code.

3. The Partnership will own operating mineral interests, as defined in the Code and in the Regulations, and none of the Partnership's revenues will be from non-working interests.

4. The General Partner will cause the Partnership to properly elect to deduct currently all Intangible Drilling and Development Costs.

5. The Partnership will have a December 31 taxable year and will report its income on the accrual basis.

6. All Partnership wells will be spudded by not later than December 31, 2007. The entire amount to be paid under any drilling and under the operating agreements entered into by the Partnership will be attributable to Intangible Drilling and Development Costs.

7. Such drilling and operating agreements will be duly executed and will govern the operation of the Partnership's wells.

8. Based upon the General Partner's review of its experience with its previous oil and gas partnerships for the past several years and upon the intended operations of the Partnership, the General Partner believes that the sum of (i) the aggregate deductions, including depletion deductions, and (ii) 350 percent of the aggregate tax credits from the Partnership will not, as of the close of any of the first five years ending after the date on which Units are offered for sale, exceed two times the aggregate cash invested by the Partners in the Partnership as of such dates. In that regard, the General Partner has reviewed the economics of its similar oil and gas partnerships for the past several years, and has represented that it has determined that none of those partnerships has resulted in a tax shelter ratio greater than two to one. Further, the General Partner has represented that the deductions and credits that are or will be represented as potentially allowable to an investor will not result in the Partnership having a "tax shelter ratio", as such term is defined in the Code and regulations thereunder, greater than two to one.

9. At least 90% of the gross income of the Partnership will constitute income derived from the exploration, development, production, and or marketing of oil and gas. The General Partner does not believe that any market will ever exist for the sale of Units and the General Partner will not make a market for the Units. Further, the Units will not be traded on an established securities market or the substantial equivalent thereof.

10. There is not now pending nor, to the knowledge of the General Partner or UNIT, threatened any action, suit or proceeding by the Internal Revenue Service under Sections 6700 or 7408 of the Internal Revenue Code relating to the promoter penalty referred to in Section 6700 of the Code with respect to any partnerships sponsored by the General Partner or UNIT. Neither the General Partner, UNIT, nor, to the knowledge of either of them, any participant in such partnerships has received any pre-filing notifications referred to in Revenue Procedure 83-73 with respect to such partnerships or the Partnership from the Internal Revenue Service.

11. The General Partner will, as nominee for the Partnership, acquire and hold title to Partnership Properties on behalf of the Partnership; the General Partner will enter into an agency agreement before the General Partner acquires any such oil and gas properties on behalf of the Partnership; the agency agreement will reflect that the General Partner's acquisition of Partnership properties is on behalf of the Partnership; and the General Partner will execute

assignments of all oil and gas interests acquired by it on behalf of the Partnership to the Partnership.

12. The Partnership and each Partner will have the objective of carrying on the business of the Partnership for profit and dividing the gain therefrom.

13. No election will be made under the Regulations for the Partnership to be treated as a corporation.

Our opinions are also subject to all the assumptions, qualifications, and limitations set forth in the following discussion, including the assumptions that each of the Partners has full power, authority, and legal right to enter into and perform the terms of the Partnership Agreement and to take any and all actions thereunder in connection with the transactions contemplated thereby.

Each prospective investor should be aware that, unlike a ruling from the Service, an opinion of counsel represents only such counsel's best judgment. **THERE CAN BE NO ASSURANCE THAT THE SERVICE WILL NOT SUCCESSFULLY ASSERT POSITIONS WHICH ARE INCONSISTENT WITH OUR OPINIONS SET FORTH IN THIS DISCUSSION OR IN THE TAX REPORTING POSITIONS TAKEN BY THE PARTNERS OR THE PARTNERSHIP. EACH PROSPECTIVE INVESTOR SHOULD CONSULT HIS OWN TAX ADVISOR TO DETERMINE THE EFFECT OF THE TAX ISSUES DISCUSSED HEREIN ON HIS INDIVIDUAL TAX SITUATION.**

PARTNERSHIP STATUS

The Partnership will be formed as a limited partnership pursuant to the Partnership Agreement and the laws of the State of Oklahoma. The characterization of the Partnership as a partnership by state or local law, however, will not be determinative of the status of the Partnership for federal income tax purposes. The availability of any federal income tax benefits to an investor is dependent upon classification of the Partnership as a partnership rather than as a corporation or as an association taxable as a corporation for federal income tax purposes.

We are of the opinion that the Partnership will be treated as a partnership for federal income tax purposes, and not as a corporation, an association taxable as a corporation or a "publicly traded partnership." However, there can be no assurance that the Service will not attempt to treat the Partnership as a corporation or as an association taxable as a corporation for federal income tax purposes. If the Service were to prevail on this issue, the tax benefits associated with taxation as a partnership would not be available to the Partners.

Although the Partnership will be validly organized as a limited partnership under the laws of the state of Oklahoma and will be subject to the Act, whether it will be treated for federal income tax purposes as a partnership or as a corporation or as an association taxable as a corporation will be determined under the Code rather than local law. As discussed below, our opinion that the Partnership will not be classified a corporation or as an association taxable as a corporation is based in part on entity classification regulations promulgated in 1996 and in part on the fact that in our opinion the Partnership will not constitute a "publicly traded partnership."

A. Association Taxable as a Corporation

Our opinion that the Partnership will not be treated as an association taxable as a corporation is based on regulations issued by the Internal Revenue Service on December 17, 1996, generally effective as of January 1, 1997, regarding the tax classification of certain business organizations (the "Check the Box Regulations").

Under the Check the Box Regulations, in general, a business entity that is not otherwise required to be treated as a corporation under such regulations will be classified as a partnership if it has two or more members, unless the business entity elects to be treated as a corporation. The Partnership is not required under the Check the Box Regulations to be treated as a corporation and the General Partner has represented that it will not elect that the Partnership be treated as a corporation. Accordingly, in our opinion the Partnership will not be treated as an association taxable as a corporation.

B. Publicly Traded Partnerships

The Revenue Act of 1987 (the "1987 Act") added Code Section 7704, "Certain Publicly Traded Partnerships Treated as Corporations." In treating certain "publicly traded partnerships" ("PTPs") as corporations for federal income tax purposes, Congress defined a PTP as any partnership, interests in which are either traded on an established securities market or readily tradable on a secondary market (or the substantial equivalent thereof). Code Section 7704(b). Regulation Section 1.7704-1(b) provides that an "established securities market" includes a national securities exchange registered under Section 6 of the Securities Exchange Act of 1934 (the "1934 Act"), a national securities exchange exempt under the 1934 Act because of the limited volume of transactions, certain foreign security laws, regional or local exchanges, and an interdealer quotation system that regularly disseminates firm buy or sell quotations by identified brokers or dealers. The General Partner has represented that the Units will not be traded on an established securities market.

Notwithstanding the above general treatment of PTPs, Code Section 7704(c) creates an exception to the treatment of PTPs as corporations for any taxable year if 90% or more of the gross income of the partnership for such taxable year consists of "qualifying income." Code

Section 7704(c)(2). For this purpose, qualifying income is defined to include, *inter alia*, “income and gains derived from the exploration, development, mining or production, processing, refining. or the marketing of any mineral or natural resource…” Code Section 7704(d)(1)(E). The General Partner has represented that for all taxable years of the Partnership, 90% or more of the Partnership’s gross income will consist of such qualifying income.

Regarding the definition of PTPs contained in the Code, the Committee Reports to the 1987 Act provide that PTPs include entities with respect to which, *inter alia*, (i) “the holder of an interest has a readily available, regular and ongoing opportunity to sell or exchange his interest through a public means of obtaining or providing information of offers to buy, sell or exchange interests,” (ii) “prospective buyers and sellers have the opportunity to buy, sell or exchange interests in a time frame and with the regularity and continuity that the existence of a market maker would provide,” and (iii) there exists a “regular plan of redemptions or repurchases” or similar acquisitions of interests in the partnership such that holders of interests have readily available, regular and ongoing opportunities to dispose of their interests.”

The Service issued Regulation Section 1.7704-1 to clarify when partnership interests that are not traded on an established securities market will be treated as readily tradable on a secondary market or the substantial equivalent thereof. Essentially, the Regulation provides that such a situation occurs if partners are readily able to buy, sell, or exchange their partnership interests in a manner that is comparable, economically, to trading on an established securities market. In addition, Notice 88-76 and the Regulation provide limited safe harbors from the definition of a PTP in advance of the issuance of final regulations. It is unclear whether the limited safe harbors provided in the Notice and Regulation would result in the Units being treated as not publicly traded and we express no opinion regarding this matter. However, the General Partner’s obligation to purchase Units pursuant to the right or presentment described in the Memorandum is conditioned upon the receipt by the Partnership from its counsel of an opinion that such offers or obligations to offer will not cause the Partnership to be treated as “publicly traded.”

Due to the presence of the opinion of counsel condition, the Partnership, in our opinion, will not be treated as a PTP prior to any purchases of Units pursuant to the right of presentment. Accordingly, the Partnership, in our opinion, will not be treated as a corporation for federal income tax purposes under Code Section 7704 in the absence of the Partnership’s interests being “readily tradable on a secondary market (or the substantial equivalent thereof).”

Notwithstanding the above, the Service may promulgate regulations or release announcements which take the position that interests in partnerships such as the Partnership are readily tradable on a secondary market or the substantial equivalent thereof. However, treatment of the Partnership as a PTP should not result in its treatment as a corporation for federal income tax purposes due to the exception contained in Code Section 7704(c) relating to PTPs meeting the 90% of gross income test so long as such gross income test is satisfied.

C. Summary

Based on the above, in our opinion the Partnership will not be treated as an association taxable as corporation for federal income tax purposes by reason of the Check the Box Regulations. Further, since any obligation of the General Partner to purchase Units is conditioned upon the receipt of an opinion of counsel that the Partnership will not be treated as a PTP, and assuming the Partnership satisfies the 90% gross income test of Code Section 7704, the Partnership, in our opinion, will not be treated as a corporation for federal income tax purposes. Accordingly, the Partnership in our opinion will be treated as partnership for federal income tax purposes. If challenged by the Service on this issue, the Partners should prevail on the merits, and each Partner should be required to report his proportionate share of the Partnership's items of income and deductions on his individual federal income tax return.

If in any taxable year the Partnership were to be treated for federal income tax purposes as a corporation or as an association taxable as a corporation, the Partnership income, gain, loss, deductions, and credits would be reflected only on its "corporate" tax return rather than being passed though to the Partners. In such event, the Partnership would be required to pay income tax at corporate rates on its net income, thereby reducing the amount of cash available to be distributed to the Partners. Additionally, all or a portion of any distribution made to Partners would be taxable as dividends, which would not be deductible by the Partnership and which would generally be treated as ordinary portfolio income to the Partners, regardless of the source from which such distributions were generated.

The discussion that follows is based on the assumption that the Partnership will be classified as a partnership for federal income tax purposes.

FEDERAL TAXATION OF THE PARTNERSHIP

Under the Code, a partnership is not a taxable entity and, accordingly, incurs no federal income tax liability. Rather, a partnership is a "pass-through" entity which is required to file an information return with the Service. In general the character of a partner's share of each item of income, gain, loss, deduction, and credit is determined at the partnership level. Each partner is allocated a distributive share of such items in accordance with the partnership agreement and is required to take such items into account in determining the partner's income. Each partner includes such amounts in income for any taxable year of the partnership ending within or with the taxable year of the partner, without regard to whether the partner has received or will receive any cash distributions from the Partnership.

A partnership anti-abuse regulation promulgated under Reg. Section 1.701-2 authorizes the Service to recharacterize a partnership transaction if (1) a partnership is formed or availed of in connection with a transaction a principal purpose of which is to reduce substantially the present value of the partners' aggregate federal income tax liability, *and* (2) the transaction is inconsistent with the intent of the Subchapter K partnership provisions. Additionally, the regulation permits the Service to treat a partnership as an aggregate of its partners, in whole or in part, as appropriate, to carry out the purpose of any provision of the Code or the regulations. The scope of this regulation is unclear at this time. Accordingly, we are unable to express an opinion as to its effect, if any, on the Partnership.

REGISTRATION AS A TAX SHELTER

The Code provides that certain investments must be registered as tax shelters with the Service. Registration numbers for such tax shelters must be supplied to investors who are required to report the numbers on their personal tax returns. Any organizer of a "potentially abusive tax shelter" and any person selling an interest in such shelter are required to maintain a list of investors in such tax shelter to whom interests were sold (together with other identifying information) and to make the list available to the Service upon request. Any tax shelter which is required to be registered and any other plan or arrangement which is of a type determined by the Treasury Regulations as having a potential for tax avoidance or evasion is considered a potentially abusive tax shelter for this purpose.

The registration requirements apply only to an investment with respect to which any person could reasonably infer from the representations made, or to be made, in connection with the offering for sale of interests in the investment that the "tax shelter ratio" for any investor is greater than two to one as of the close of any of the first five years ending after the date on which such investment is offered for sale.

The General Partner has represented that, (i) based upon its experience with its oil and gas partnerships and upon the intended operations of the Partnership, it does not believe that the Partnership will have a tax shelter ratio greater than two to one, (ii) the deductions and credits that are or will be represented as potentially allowable to an investor will not result in any Partnership having a tax shelter ratio greater than two to one, and (iii) based upon a review of the economics of its similar oil and gas partnerships for the past several years, it has determined that none of those partnerships has resulted in a tax shelter ratio greater than two to one. Accordingly, the General Partner does not intend to cause the Partnership to register with the Service as a tax shelter. Based on the foregoing representations, we are of the opinion that the Partnership will not be required to register with the Service as a tax shelter.

If it is subsequently determined that the Partnership was required to be registered with the Service as a tax shelter, the Partnership would be subject to certain penalties under Code

Section 6707, including a penalty ranging from $500 to 1% of the aggregate amount invested in Units for failing to register and $100 for each failure to furnish to a Partner a tax shelter registration number, and each Partner would be liable for a $250 penalty for failure to include the tax registration number on his tax return, unless such failure was due to reasonable cause. A Partner also would be liable for a penalty of $100 for failing to furnish the tax shelter registration number to any transferee of his Partnership interest. We can give no assurance that, if the Partnership is determined to be a tax shelter which must be registered with the Service, the above penalties will not apply.

OWNERSHIP OF PARTNERSHIP PROPERTIES

The General Partner has indicated that it, as nominee for the Partnership (the "Nominee"), will acquire and hold title to Partnership Properties on behalf of the Partnership. The Nominee and the Partnership will enter into an agency agreement before the Nominee acquires any oil and gas properties on behalf of the Partnership. That agency agreement will reflect that the Nominee's acquisition of Partnership Properties is on behalf of the Partnership. For various cost and procedural reasons, the assignments of all oil and gas interests acquired by the Nominee on behalf of the Partnership to the Partnership will not be recorded in the real estate records in the counties in which the Partnership Properties are located. That is, while the Partnership will be the owner of the Partnership Properties, there will be no public record of that ownership. It is possible that the Service could assert that the Nominee should be treated for federal income tax purposes as the owner of the Partnership Properties, notwithstanding the assignment of those Partnership Properties to the Partnership. If the Service were to argue successfully that the Nominee should be treated as the tax owner of the Partnership Properties, there would be significant adverse federal income tax consequences to the Limited Partners, such as the unavailability of depletion deductions in respect of income from Partnership Properties. The Service is concerned that taxpayers not be able to shift the tax consequences of transactions between parties based on the parties' declaration that one party is the agent of another; the Service generally requires that taxpayers respect the form of their transactions and ownership of property. Based on this concern, the Service may challenge the Partnership's treatment of Partnership Properties, and tax attributes thereof, which are held of record by the Nominee.

In *Commissioner of Internal Revenue v. Bollinger*, 485 U.S. 340 (1988), the United States Supreme Court reviewed a principal-agent relationship and held for the taxpayer in concluding that the principal should be treated as the tax owner of property held in the name of the agent. In that case the Supreme Court noted that "It seems to us that the genuineness of the agency relationship is adequately assured, and tax-avoiding manipulation adequately avoided, when the fact that the corporation is acting as agent for its shareholders with respect to a particular asset is set forth in a written agreement at the time the asset is acquired, the corporation functions as agent and not principal with respect to the asset for all purposes, and the corporation is held out as the agent and not principal in all dealings with third parties relating to the asset." While the

Partnership and the Nominee will have in place an agreement defining their relationship before any Partnership Properties are acquired by the Nominee and the Nominee will function as agent with respect to those Partnership Properties on behalf of the Partnership, the Nominee will not hold itself out to all third parties as the agent of the Partnership in dealings relating to the Partnership Properties. Unlike the relationship between the principal and the agent in *Bollinger*, the Nominee will, however, assign title to Partnership Properties to the Partnership, but will not record those assignments. Accordingly, the facts related to the relationship between the Nominee and the Partnership are not the same as the facts in *Bollinger* and it is not clear that the failure of the Nominee to hold itself out to third parties as the agent of the Partnership in dealings relating to Partnership Properties would result in the treatment of the Nominee as the tax owner of the Partnership Properties. For the foregoing reasons, we have not expressed an opinion on this issue, but we believe that substantial arguments may be made that the Partnership should be treated as the tax owner of Partnership Properties acquired by the Nominee on the Partnership's behalf. If the Partnership were not treated as the tax owner of the Partnership Properties, then our conclusions with respect to the following discussions which relate to the Partners' deduction of tax items which are derived from Partnership Properties, such as IDC, depletion and Depreciation, would not be applicable.

INTANGIBLE DRILLING AND DEVELOPMENT COSTS DEDUCTIONS

Under Code Section 263(a), taxpayers are denied deductions for capital expenditures, which expenditures are those that generally result in the creation of an asset having a useful life which extends substantially beyond the close of the taxable year. See also Treas. Reg. Section 1.461-1(a)(2). In *Indopco, Inc. v. Commissioner*, 92-1 USTC paragraph 50,113 (1992), the Supreme Court seemed to further limit the capitalization criteria by stating that the costs should be capitalized when they provide benefits that extend beyond one tax year. Notwithstanding these statutory and judicial general rules, Congress has granted to the Secretary of the Treasury the authority to prescribe regulations that would allow taxpayers the option of deducting, rather than capitalizing, intangible drilling and development costs ("IDC"). Code Section 263. The Secretary's rules are embodied in Treas. Reg. Section 1.612-4 and state that, in general, the option to deduct IDC applies only to expenditures for drilling and development items that do not have a salvage value.

With respect to IDC incurred by a partnership, Code Section 703 and Treas. Reg. Section 1.703-1(b) provide that the option to deduct such costs is to be exercised at the partnership level and in the year in which the deduction is to be taken. All partners are bound by the partnership's election. The General Partner has represented that the Partnership will elect to deduct IDC in accordance with Treas. Reg. Section 1.612-4. In this regard, subject to such provision, Limited Partners will be entitled to deduct IDC against passive income in the year in which the investment is made, provided wells are spudded within the first ninety days of the following year.

A. Classification of Costs

In general, IDC consists of those costs which in and of themselves have no salvage value. Treas. Reg. Section 1.612-4(a) provides examples of items to which the option to deduct IDC applies, including all amounts paid for labor, fuel, repairs, hauling, and supplies, or any of them, which are used (i) in the drilling, shooting, and cleaning of wells, (ii) in such clearing of ground, draining, road making, surveying, and geological works as are necessary in the preparation for the drilling of wells, and (iii) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. The Service, in Rev. Rul. 70-414, 1970-2 C.B. 132, set forth further classifications of items subject to the option and those considered capital in nature. The ruling provides that the following items are not subject to the election of Treas. Reg. Section 1.612-4(a): (i) oil well pumps (upon initial completion of the well), including the necessary housing structures; (ii) oil well pumps (after the well has flowed for a time), including the necessary housing structures; (iii) oil well separators, including the necessary housing structures; (iv) pipelines from the wellhead to oil storage tanks on the producing lease; (v) oil storage tanks on the producing lease; (vi) salt water disposal equipment, including any necessary pipelines; (vii) pipelines from the mouth of a gas well to the first point of control, such as a common carrier pipeline, natural gasoline plant, or carbon black plant; (viii) recycling equipment, including any necessary pipelines; and (ix) pipelines from oil storage tanks on the producing leasehold to a common carrier pipeline.

A partnership's classification of a cost as IDC is not binding on the government, which might reclassify an item labeled as IDC as a cost which must be capitalized. In *Bernuth v. Commissioner*, 57 T.C. 225 (1971), *aff'd*, 470 F.2d 710 (2nd Cir. 1972), the Tax Court denied taxpayers a deduction for that portion of a turnkey drilling contract price that was in excess of a reasonable cost for drilling the wells in question under a turnkey contract, holding that the amount specified in the turnkey contract was not controlling. Similarly, the Service, in Rev. Rul. 73-211, 1973-1 C.B. 303, concluded that excessive turnkey costs are not deductible as IDC:

> [o]nly that portion of the amount of the taxpayer's total investment that is attributable to intangible drilling and development costs that would have been incurred in an arm's-length transaction with an unrelated drilling contractor (in accordance with the economic realities of the transaction) is deductible [as IDC].

To the extent the Partnership's prices meet the reasonable price standards imposed by *Bernuth*, *supra*, and Rev. Rul 73-211, *supra*, and to the extent such amounts are not allocable to tangible property, leasehold costs, and the like, the amounts paid to the General Partner or its affiliates under drilling contracts should qualify as IDC and should be deductible at the time described below under "B. Timing of Deductions". That portion of the amount paid to the

General Partner or its affiliates that is in excess of the amount that would be charged by an independent driller under similar conditions will not qualify as IDC and will be required to be capitalized.

We are unable to express an opinion regarding the reasonableness or proper characterization of the payments under the drilling contracts, since the determination of whether the amounts are reasonable or excessive is inherently factual in nature. No assurance can be given that the Service will not characterize a portion of the amount paid to the General Partner or its affiliates as an excessive payment, to be capitalized as a leasehold cost, assignment fee, syndication fee, organization fee, or other cost, and not deductible as IDC. To the extent not deductible such amounts will be included in the Partners' bases in their interests in the Partnership.

B. Timing of Deductions

As described above, Code Section 263(c) and Treas. Reg. Section 1.612-4 allow the Partnership to expense IDC as opposed to capitalizing such amounts. Even if the Partnership elects to expense the IDC, assuming a taxpayer is otherwise entitled to such a deduction, the taxpayer may elect to capitalize all or a part of the IDC and amortize the same on a straight-line basis over a sixty month period, beginning with the taxable month in which such expenditure is made. Code Section 59(e)(1) and (2)(c).

For taxpayers entitled to deduct IDC, the timing of such deduction can vary, depending, in part, upon the taxpayer's method of accounting. The General Partner has represented that the Partnership will use the accrual method of accounting. Under the accrual method, income is recognized when all the events have occurred which fix the right to receive such income and the amount thereof can be determined with reasonable accuracy. Reg. Section 1.451-1(a). With respect to deductions, recognition results when all events which establish liability have occurred and the amount thereof can be determined with reasonable accuracy. Reg. Section 1.461-1(a)(2). Regarding deductions, Code Section 461(h)(1) provides that ". . . the all events test shall not be treated as met any earlier than when economic performance with respect to such item occurs."

Code Section 461(i)(2), provides that, in the case of a "tax shelter," economic performance with respect to the act of drilling an oil or gas well will ". . . be treated as having occurred within a taxable year if drilling of the well commences before the close of the 90th day after the close of the taxable year." The Code Section 461 definition of a "tax shelter" is expansive and would include the Partnership. However, with respect to a tax shelter which is a partnership, the maximum deduction that would be allowable for any prepaid expenses under this exception would be limited to the partner's "cash basis" in the partnership. Code Section 461(i)(2)(B)(i). Such "cash basis equals the partner's adjusted basis in the partnership, determined without regard to (i) any liability of the partnership and (ii) any amount borrowed by the partner with respect to the partnership which (I) was arranged by the partnership or by any person who participated in the organization, sale, or management of the partnership (or any person related to such person within the meaning of Code Section 465(b)(3)(C)) or (II) was secured by any assets of the partnership". Code Section 461(i)(2)(C). The General Partner has represented that drilling operations for Partnership wells will commence by the spudding of each well on or before December 31, 2007. If completion is warranted, each well will be completed with due diligence thereafter. Further the General Partner has represented that, in any event, the Partnership will not have any such liability referred to in Code Section 461(i)(2)(C), and the Partners will not so incur any such debt so as to result in application of the limiting provisions contained in Code Section 461(i)(2)(B)(i).

Notwithstanding the above, the deductibility of any prepaid IDC will be subject to the limitations of case law. These limitations provide that prepaid IDC is deductible when paid if (i) the expenditure constitutes a payment that is not merely a deposit, (ii) the payment is made for a business purpose, and (iii) deductions attributable to such outlay do not result in a material distortion of income. See *Keller v. Commissioner*, 79 T.C. 7 (1982), *aff'd*, 725 F.2d 1173 (8th Cir. 1984), Rev. Rul. 71-252, 1971-1 C.B. 146, *Pauley v. U.S.*, 63-1 U.S.T.C. paragraph 9280 (S.D. Cal. 1963), Rev. Rul. 80-71, 1980-1 C.B. 106, *Jolley v. Commissioner*, 47 T.C.M. 1082 (1984), *Dillingham v. U.S.*, 81-2 U.S.T.C. paragraph 9601 (W.D. Okla. 1981), and *Stradlings Building Materials, Inc. v. Commissioner*, 76 T.C. 84 (1981). Generally, these requirements may be met by a showing of a legally binding obligation (i.e., the payment was not merely a deposit), of a legitimate business purpose for the payment, that performance of the services was required within a reasonable time, and of an arm's-length price. Similar requirements apply to cash basis taxpayers seeking to deduct prepaid IDC.

The General Partner is unable to represent that all of the Partnership's wells will be completed in 2007; however, the General Partner has represented that any such well that is not completed in 2007 will be spudded by not later than December 31, 2007.

The Service has challenged the timing of the deduction of IDC when the wells giving rise to such deduction have been completed in a year subsequent to the year of prepayment. The decisions noted above hold that prepayments of IDC by a cash basis taxpayer are, under certain circumstances, deductible in the year of prepayment if some work is performed in the year of prepayment even though the well is not completed that year.

In *Keller v. Commissioner, supra*, the Eighth Circuit Court of Appeals applied a three-part test for determining the current deductibility of prepaid IDC by a cash basis taxpayer, namely whether (i) the expenditure was a payment or a mere deposit, (ii) the payment was made for a valid business purpose and (iii) the prepayment resulted in a material distortion of income. The facts in that case dealt with two different forms of drilling contracts: footage or day-work contracts and turnkey contracts. Under the turnkey contracts, the prepayments were not refundable in any event, but in the event work was stopped on one well the remaining unused amount would be applied to another well to be drilled on a turnkey basis. Contrary to the Service's argument that this substitution feature rendered the payment a mere deposit, the court in *Keller* concluded that the prepayments were indeed "payments" because the taxpayer could not compel a refund. The court further found that the deduction clearly reflected income because under the unique characteristics of the turnkey contract the taxpayer locked in the price and shifted the drilling risk to the contractor, for a premium, effectively getting its bargained for benefit in the year of payment. Therefore, the court concluded that the cash basis taxpayers in that case properly could deduct turnkey payments in the year of payment. With respect to the prepayments under the footage or day-work contracts, however, the court found that the payments were mere deposits on the facts of the case, because the partnership had the power to compel a refund. The court was also unconvinced as to the business purpose for prepayment under the footage or day-work contracts, primarily because the testimony indicated that the drillers would have provided the required services with or without prepayment.

Under the terms of drilling and operating agreements to be entered into by and between the Partnership and the General Partners or its affiliates, if amounts paid by the Partnership prior to the commencement of drilling exceed amounts due the General Partner or its affiliates thereunder, the General Partner or its affiliates will not refund any portion of amounts paid by the Partnership, but rather will create a credit once the actual costs incurred by the General Partner or its affiliates are compared to the amounts paid.

The Service has adopted the position that the relationship between the parties may provide evidence that the drilling contract between the parties requiring prepayment may not be a bona fide arm's-length transaction, in which case a portion of the prepayment may be disallowed as being a "non-required payment." Section 4236, Internal Revenue Service Examination Tax Shelters Handbook (6-27-85). A similar position is taken by the Service in the Tax Shelter Audit Technique Guidelines. Internal Revenue Service Examination Tax Shelter Handbook.

The Service has formally applied its position on prepayments to related parties in Revenue Ruling 80-71. 1980-1 C.B. 106. In this ruling, a subsidiary corporation, which was a general partner in an oil and gas limited partnership, prepaid the partnership's drilling and completion costs under a turnkey contract entered into with the corporate parent of the general partner. The agreement did not provide for any date for commencing drilling operations and the contractor, which did not own any drilling equipment, was to arrange for the drilling equipment for the wells through subcontractors. Revenue Ruling 71-252, *supra*, was factually distinguished on the grounds of the business purpose of the transaction, immediate expenditure of prepaid receipts, and completion of the wells within two and one-half months. Rev. Rul. 80-71 found that the prepayment was not made in accordance with customary business practice and held on the facts that the payment was deductible in the tax year that the related general contractor paid the independent subcontractor.

However, in *Tom B. Dillingham v. United States*, 1981-2 USTC paragraph 9601 (D.C. Okla. 1981), the court held that, on the facts before it, a contract between related parties requiring a prepaid IDC did give rise to a deduction in the year paid. In that case, Basin Petroleum Corp. ("Basin") was the general partner of several drilling partnerships and also served as the partnership operator and general contractor. As general contractor, Basin was to conduct the drilling of the wells at a fixed price on a turnkey basis under an agreement that required payment prior to the end of the year in question. The stated reason for the prepayment was to provide Basin with working capital for the drilling of the wells and to temporarily provide funds to Basin for other operations. The agreement required drilling to commence within a reasonable period of time, and all wells were completed within the following year. Some of the wells were drilled by Basin with its own rigs and some were drilled by subcontractors. The court stated:

> The fact that the owner and contractor is the general partner of the partnership-owner does not change this result where, as here, the Plaintiffs have shown that prepayment was required for a legitimate business purpose and the transaction was not a sham to merely permit Plaintiff to control the timing of the deduction. IRC, Sec. 707(a). Plaintiffs were entitled to rely upon Revenue Ruling 71-252 by reason of Income Tax Regulations 26 C.F.R. Section 601.601(d)(2)(v)(e) . . .

Notwithstanding the foregoing, no assurance can be given that the Service will not challenge the current deduction of IDC because of the prepayment being made to a related party. If the Service were successful with such challenge, the Partners' deductions for IDC would be deferred to later years.

The timing of the deductibility of prepaid IDC is inherently a factual determination which is to a large extent predicated on future events. The General Partner has represented that the drilling and operating agreements to be entered into with an affiliate of the General Partner by the Partnership will be duly executed by and delivered to such affiliate, the Partnership and the General Partner as attorney-in-fact for the Partners and will govern the drilling, and, if warranted, the completion of each of the Partnership's wells. Based upon this representation and others included within the opinion and assuming that the drilling and operating agreements will be performed in accordance with their terms, we are of the opinion that the payment for IDC under the drilling and operating agreements, if made in 2007, will be allowable as a deduction in 2007, subject to the other limitations discussed in this opinion. Although the General Partner will attempt to satisfy each requirement of the Service and judicial authority for deductibility of IDC in 2007, no assurance can be given that the Service will not successfully contend that the IDC of a well which is not completed until 2008 are not deductible in whole or in part until 2008.

C. Recapture of IDC

IDC which has been deducted is subject to recapture as ordinary income upon certain dispositions (other than by abandonment, gift, death, or tax-free exchange) of an interest in an oil or gas property. IDC previously deducted that is allocable to the property (directly or through the ownership of an interest in a partnership) and which would have been included in the adjusted basis of the property is recaptured to the extent of any gain realized upon the disposition of the property. Treasury Regulations provide that recapture is determined at the partner level (subject to certain anti-abuse provisions). Reg. Section 1.1254-5(b). Where only a portion of recapture property is disposed of, any IDC related to the entire property is recaptured to the extent of the gain realized on the portion of the property sold. In the case of the disposition of an undivided interest in a property (as opposed to the disposition of a portion of the property), a proportionate part of the IDC with respect to the property is treated as allocable to the transferred undivided interest to the extent of any realized gain. Reg. Section 1.1254-1(c).

DEPLETION DEDUCTIONS

The owner of an economic interest in an oil and gas property is entitled to claim the greater of percentage depletion or cost depletion with respect to oil and gas properties which qualify for such depletion methods. In the case of partnerships, the depletion allowance must be computed separately by each partner and not by the partnership. Code Section 613A(c)(7)(D). Notwithstanding this requirement, however, the Partnership, pursuant to Section 3.01(d)(i) of the Partnership Agreement, will compute a "simulated depletion allowance" at the Partnership level, solely for the purposes of maintaining Capital Accounts. Code Sections 613A(d)(2) and 613A(d)(4).

Cost depletion for any year is determined by multiplying the number of units (*e.g.*, barrels of oil or Mcf of gas) sold during the year by a fraction, the numerator of which is the cost of the mineral interest and the denominator of which is the estimated recoverable units of reserve available as of the beginning of the depletion period. See Treas. Reg. Section 1.611-2(a). In no event can the cost depletion exceed the adjusted basis of the property to which it relates.

Percentage depletion is generally available only with respect to the domestic oil and gas production of certain "independent producers." In order to qualify as an independent producer, the taxpayer, either directly or through certain related parties, may not be involved in the refining of more 50,000 barrels of oil (or equivalent of gas) on any day during the taxable year or in the retail marketing of oil and gas products exceeding $5 million per year in the aggregate.

In general, (i) component members of a controlled group of corporations, (ii) corporations, trusts, or estates under common control by the same or related persons and (iii) members of the same family (an individual, his spouse and minor children) are aggregated and treated as one taxpayer in determining the quantity of production (barrels of oil or cubic feet of gas per day) qualifying for percentage depletion under the independent producer's exemption. Code Section 613A(c)(8). No aggregation is required among partners or between a partner and a partnership. An individual taxpayer is related to an entity engaged in refining or retail marketing if he owns 5% or more of such entity. Code Section 613A(d)(3).

Percentage depletion is a statutory allowance pursuant to which, under current law, a minimum deduction equal to 15% of the taxpayer's gross income from the property is allowed in any taxable year, not to exceed (i) 100% of the taxpayer's taxable income from the property (computed without the allowance for depletion) or (ii) 65% of the taxpayer's taxable income for the year (computed without regard to percentage depletion and net operating loss and capital loss carrybacks). Code Sections 613(a) and 613A(d)(1). The rate of the percentage depletion deduction will vary with the price of oil. In the case of production from marginal properties, the percentage depletion rate may be increased. Section 613A(c)(6). For purposes of computing the percentage depletion deduction, "gross income from the property" does not include any lease bonus, advance royalty, or other amount payable without regard to production from the property. Code Section 613A(d)(5). Depletion deductions reduce the taxpayer's adjusted basis in the property. However, unlike cost depletion, deductions under percentage depletion are not limited to the adjusted basis of the property; the percentage depletion amount continues to be allowable as a deduction after the adjusted basis has been reduced to zero.

Percentage depletion will be available, if at all, only to the extent that a taxpayer's average daily production of domestic crude oil or domestic natural gas does not exceed the taxpayer's depletable oil quantity or depletable natural gas quantity, respectively. Generally, the taxpayer's depletable oil quantity equals 1,000 barrels and depletable natural gas quantity equals 6,000,000 cubic feet. Code Section 613A(c)(3) and (4). In computing his individual limitation, a Partner will be required to aggregate his share of the Partnership's oil and gas production with his share of production from all other oil and gas investments. Code Section 613A(c). Taxpayers who have both oil and gas production may allocate the deduction limitation between the two types of production.

The availability of depletion, whether cost or percentage, will be determined separately by each Partner. Each Partner must separately keep records of his share of the adjusted basis in an oil or gas property, adjust such share of the adjusted basis for any depletion taken on such property, and use such adjusted basis each year in the computation of his cost depletion or in the computation of his gain or loss on the disposition of such property. These requirements may place an administrative burden on a Partner. For properties placed in service after 1986, depletion deductions, to the extent they reduce the basis of an oil and gas property, are subject to recapture under Section 1254.

SINCE THE AVAILABILITY OF PERCENTAGE DEPLETION FOR A PARTNER IS DEPENDENT UPON THE STATUS OF THE PARTNER AS AN INDEPENDENT PRODUCER, WE ARE UNABLE TO RENDER ANY OPINION AS TO THE AVAILABILITY OF PERCENTAGE DEPLETION. EACH PROSPECTIVE INVESTOR IS URGED TO CONSULT WITH HIS PERSONAL TAX ADVISOR TO DETERMINE WHETHER PERCENTAGE DEPLETION WOULD BE AVAILABLE TO HIM.

DEPRECIATION DEDUCTIONS

The Partnership will claim depreciation, cost recovery, and amortization deductions with respect to its basis in Partnership Property as permitted by the Code. For most tangible personal property placed in service after December 31, 1986, the "modified accelerated cost recovery system" ("MACRS") must be used in calculating the cost recovery deductions. Thus, the cost of lease equipment and well equipment, such as casing, tubing, tanks, and pumping units, and the cost of oil or gas pipelines cannot be deducted currently but must be capitalized and recovered under "MACRS." The cost recovery deduction for most equipment used in domestic oil and gas exploration and production and for most of the tangible personal property used in natural gas gathering systems is calculated using the 200% declining balance method switching to the straight-line method, a seven-year recovery period, and a half-year convention.

INTEREST DEDUCTIONS

In the Transaction, the Limited Partners will acquire their interests by remitting cash in the amount of $1,000 per Unit to the Partnership (employees of Unit Corporation and its subsidiaries may elect payroll withholding). In no event will the Partnership accept notes in exchange for a Partnership interest. Nevertheless, without any assistance of the General Partner or any of its affiliates, some Partners may choose to borrow the funds necessary to acquire a Unit and may incur interest expense in connection with those loans. Based upon the purely factual nature of any such loans, we are unable to express an opinion with respect to the deductibility of any interest paid or incurred thereon.

TRANSACTION FEES

The Partnership may classify a portion of the fees or expense reimbursement payments (the "Fees") to be paid to third parties and to the General Partner or its affiliates as expenses which are deductible as organizational expenses or otherwise. There is no assurance that the Service will allow the deductibility of such expenses and we express no opinion with respect to the allocation of the Fees to deductible and nondeductible items.

Generally, expenditures made in connection with the creation of, and with sales of interests in, a partnership will fit within one of several categories.

A partnership may elect to amortize and deduct its organizational expenses (as defined in Code Section 709(b)(2) and in Reg. Section 1.709-2(a)) ratably over a period of not less than 60 months commencing with the month the partnership begins business. Organizational expenses are expenses which (i) are incident to the creation of the partnership, (ii) are chargeable to capital account, and (iii) are of a character which, if expended incident to the creation of a partnership having an ascertainable life, would (but for Code Section 709(a)) be amortized over such life. *Id.* Examples of organizational expenses are legal fees for services incident to the organization of the partnership, such as negotiation and preparation of a partnership agreement, accounting fees for services incident to the organization of the partnership, and filing fees. Reg. Section 1.709-2(a).

Under Code Section 709, no deduction is allowable for “syndication expenses,” examples of which include brokerage fees, registration fees, legal fees of the underwriter or placement agent and the issuer (general partners or the partnership) for securities advice and for advice pertaining to the adequacy of tax disclosures in the Memorandum or private placement memorandum for securities law purposes, printing costs, and other selling or promotional material. These costs must be capitalized. Reg. Section 1.709-2(b). Payments for services performed in connection with the acquisition of capital assets must be amortized over the useful life of such assets. Code Section 263.

Under Code Section 195, no deduction is allowable with respect to “start-up expenditures,” although such expenditures may be capitalized and amortized over a period of not less than 60 months. Start-up expenditures are defined as amounts (i) paid or incurred in connection with (A) investigating the creation or acquisition of an active trade or business, (B) creating an active trade or business, or (C) any activity engaged in for profit and for the production of income before the day on which the active trade or business begins, in anticipation of such activity becoming an active trade or business, and (ii) which, if paid or incurred in connection with the operation of an existing active trade or business (in the same field as the trade or business referred to in (i) above), would be allowable as a deduction for the taxable year in which paid or incurred. Code Section 195(c)(1).

The Partnership intends to make expense reimbursement payments to the General Partner, as described in the Memorandum. To be deductible, compensation paid to a general partner must be for services rendered by the partner other than in his capacity as a partner or for compensation determined without regard to partnership income. Fees which are not deductible because they fail to meet this test may be treated as special allocations of income to the recipient partner (see *Pratt v. Commissioner*, 550 F.2d 1023 (5th Cir. 1977)), and thereby decrease the net loss or increase the net income among all partners.

To the extent these expenditures described in the Memorandum are considered syndication costs, they will be nondeductible by the Partnership. To the extent attributable to organization fees (such as the amounts paid for legal services incident to the organization of the Partnership), the expenditures may be amortizable over a period of not less than 60 months, commencing with the month the Partnership begins business, if the Partnership so elects; if no election is made, no deduction is available. Finally, to the extent any portion of the expenditures would be treated as “start-up,” they could be amortized over a 60 month or longer period, provided the proper election was made.

Due to the inherently factual nature of the proper allocation of expenses among nondeductible syndication expenses, amortizable organization expenses, amortizable “start-up” expenditures, and currently deductible items, and because the issues involve questions concerning both the nature of the services performed and to be performed and the reasonableness of amounts charged, we are unable to express an opinion regarding such treatment. If the Service were to successfully challenge the General Partner’s allocations, a Partner’s taxable income could be increased, thereby resulting in increased taxes and in potential liability for interest and penalties.

BASIS AND AT RISK LIMITATIONS

A Partner’s share of Partnership losses will not be allowed as a deduction to the extent such share exceeds the amount of the Partner’s adjusted tax basis in his Units. A Partner’s initial adjusted tax basis in his Units will generally be equal to the cash he has invested to purchase his Units. Such adjusted tax basis will generally be increased by (i) additional amounts invested in the Partnership, including his share of net income, (ii) additional capital contributions, if any, and (iii) his share of Partnership borrowings, if any, based on the extent of his economic risk of loss for such borrowings. Such adjusted tax basis will generally be reduced, but not below zero by (i) his share of loss, (ii) his depletion deductions on his share of oil and gas income (until such deductions exhaust his share of the basis of property subject to depletion), (iii) the amount of cash and the adjusted basis of property other than cash distributed to him, and (iv) his share of reduction in the amount of indebtedness previously included in his basis.

In addition, Code Section 465 provides, in part, that, if an individual or a closely held C (*i.e.*, regularly taxed) corporation engages in any activity to which Code Section 465 applies, any loss from that activity is allowed only to the extent of the aggregate amount with respect to which the taxpayer is “at risk” for such activity at the close of the taxable year. Code Section 465(a)(1). A closely held C corporation is a corporation more than fifty percent (50%) of the stock of which is owned, directly or indirectly, at any time during the last half of the taxable year by or for not more than five (5) individuals. Code Sections 465(a)(1)(B), 542(a)(2). For purposes of Code Section 465, a loss is defined as the excess of otherwise allowable deductions attributable to an activity over the income received or accrued from that activity. Code Section 465(d). Any such loss disallowed by Code Section 465 shall be treated as a deduction allocable to the activity in the first succeeding taxable year. Code Section 465(a)(2).

Code Section 465(b)(1) provides that a taxpayer will be considered as being “at risk” for an activity with respect to amounts including (i) the amount of money and the adjusted basis of other property contributed by the taxpayer to the activity, and (ii) amounts borrowed with respect to such activity to the extent that the taxpayer (A) is personally liable for the repayment of such amounts, or (B) has pledged property, other than property used in the activity, as security for such borrowed amounts (to the extent of the net fair market value of the taxpayer’s interest in such property). No property can be taken into account as security if such property is directly or indirectly financed by indebtedness that is secured by property used in the activity. Code Section 465(b)(2). Further, amounts borrowed by the taxpayer shall not be taken into account if such amounts are borrowed (i) from any person who has an interest (other than an interest as a creditor) in such activity, or (ii) from a related person to a person (other than the taxpayer) having such an interest. Code Section 465(b)(3).

Related persons for purposes of Code Section 465(b)(3) are defined to include related persons within the meaning of Code Section 267(b) (which describes relationships between family members, corporations and shareholders, trusts and their grantors, beneficiaries and fiduciaries, and similar relationships), Code Section 707(b)(1) (which describes relationships between partnerships and their partners) and Code Section 52 (which describes relationships between persons engaged in businesses under common control). Code Section 465(b)(3)(C).

Finally, no taxpayer is considered at risk with respect to amounts for which the taxpayer is protected against loss through nonrecourse financing, guarantees, stop loss agreements, or other similar arrangements. Code Section 465(b)(4).

The Code provides that a taxpayer must recognize taxable income to the extent that his “at risk” amount is reduced below zero. This recaptured income is limited to the sum of the loss deductions previously allowed to the taxpayer, less any amounts previously recaptured. A taxpayer may be allowed a deduction for the recaptured amounts included in his taxable income if and when he increases his amount “at risk” in a subsequent taxable year.

The Treasury has published proposed regulations relating to the at risk provisions of Code Section 465. These proposed regulations provide that a taxpayer’s at risk amount will include “personal funds” contributed by the taxpayer to an activity. Prop. Reg. Section 1.465-22(a). “Personal funds” and “personal assets” are defined in Prop. Reg. Section 1.465-9(f) as funds and assets which (i) are owned by the taxpayer, (ii) are not acquired through borrowing, and (iii) have a basis equal to their fair market value.

In addition to a taxpayer's amount at risk being increased by the amount of personal funds contributed to the activity, the excess of the taxpayer's share of all items of income received or accrued from an activity during a taxable year over the taxpayer's share of allowable deductions from the activity for the year will also increase the amount at risk. Prop. Reg. Section 1.465-22. A taxpayer's amount at risk will be decreased by (i) the amount of money withdrawn from the activity by or on behalf of the taxpayer, including distributions from a partnership, and (ii) the amount of loss from the activity allowed as a deduction under Code Section 465(a). *Id.*

The Partners will purchase Units by tendering cash (or payroll deductions) to the Partnership. To the extent the cash contributed constitutes the "personal funds" of the Partners, the Partners should be considered at risk with respect to those amounts. To the extent the cash contributed constitutes "personal funds," in our opinion, neither the at risk rules nor the adjusted basis rules will limit the deductibility of losses generated from the Partnership.

PASSIVE LOSS AND CREDIT LIMITATIONS

A. Introduction

Code Section 469 provides that the deductibility of losses generated from passive activities will be limited for certain taxpayers. The passive activity loss limitations apply to individuals, estates, trusts, and personal service corporations as well as, to a lesser extent, closely held C corporations. Code Section 469(a)(2).

The definition of a "passive activity" generally encompasses all rental activities as well as all activities with respect to which the taxpayer does not "materially participate." Code Section 469(c). Notwithstanding this general rule, however, the term "passive activity" does not include "any working interest in any oil or gas property which the taxpayer holds directly or through an entity which does not limit the liability of the taxpayer with respect to such interest." Code Section 469(c)(3)(4).

A passive activity loss ("PAL") is defined as the amount (if any) by which the aggregate losses from all passive activities for the taxable year exceed the aggregate income from all passive activities for such year. Code Section 469(d)(1).

Classification of an activity as passive will result in the income and expenses generated therefrom being treated as "passive" except to the extent that any of the income is "portfolio" income and except as otherwise provided in regulations. Code Section 469(e)(1)(A). Portfolio income is income from, *inter alia*, interest, dividends. and royalties not derived in the ordinary course of a trade or business. Income that is neither passive nor portfolio is "net active income." Code Section 469(e)(2)(B).

With respect to the deductibility of PALs, individuals and personal service corporations will be entitled to deduct such amounts only to the extent of their passive income whereas closely held C corporations (other than personal service corporations) can offset PALs against both passive and net active income, but not against portfolio income. Code Section 469(a)(1), (e)(2). In calculating passive income and loss, however, all activities of the taxpayer are aggregated. Code Section 469(d)(1). PALs disallowed as a result of the above rules will be suspended and can be carried forward indefinitely to offset future passive (or passive and active, in the case of a closely held C corporation) income. Code Section 469(b).

Upon the disposition of an entire interest in a passive activity in a fully taxable transaction not involving a related party, any passive loss that was suspended by the provisions of the Code Section 469 passive activity rules is deductible from either passive or non-passive income. The deduction must be reduced, however, by the amount of income or gain realized from the activity in previous years.

As noted above, a passive activity includes an activity with respect to which the taxpayer does not "materially participate." A taxpayer will be considered as materially participating in a venture only if the taxpayer is involved in the operations of the activity on a "regular, continuous, and substantial" basis. Code Section 469(h)(1). With respect to the determination as to whether a taxpayer's participation in an activity is material, temporary regulations issued by the Service provide that, except for limited partners in a limited partnership, an individual will be treated as materially participating in an activity if and only if (i) the individual participates in the activity for more than 500 hours during such year, (ii) the individual's participation in the activity for the taxable year constitutes substantially all of the participation in such activity of all individuals for such year, (iii) the individual participates in the activity for more than 100 hours during the taxable year, and such individual's participation in such activity is not less than the participation in the activity of any other individual for such year, (iv) the activity is a trade or business activity of the individual, the individual participates in the activity for more than 100 hours during such year, and the individual's aggregate participation in all significant participation activities of this type during the year exceeds 500 hours, (v) the individual materially participated in the activity for 5 of the last 10 years, or (vi) the activity is a personal service activity and the individual materially participated in the activity for any 3 preceding years. Temp. Reg. Section 1.469-5T(a).

Notwithstanding the above, and except as may be provided in regulations, Code Section 469(h)(2) provides that no limited partnership interest will be treated as an interest with respect to which a taxpayer materially participates. The temporary regulations create several exceptions to this rule and provide that a limited partner will not be treated as not materially participating in an activity of the partnership of which he is a limited partner if the limited partner would be treated as materially participating for the taxable year under paragraph (a)(1), (5), or (6) of Reg. Section 1.469-5T (as described in (i), (v), and (vi) of the above paragraph) if the individual were not a limited partner for such taxable year. Temp. Reg. Section 1.469-5T(e). For purposes of this rule, a partnership interest of an individual will not be treated as a limited partnership interest for the taxable year if the individual is an Additional General Partner in the partnership at all times during the partnership's taxable year ending with or within the individual's taxable year. *Id.*

B. Limited Partner Interests

If an investor invests in the Partnership as a Limited Partner, in our opinion, his distributive share of the Partnership's losses will be treated as PALs, the availability of which will be limited to his passive income thereon. If the Limited Partner does not have sufficient passive income to utilize the PALs, the disallowed PALs will be suspended and may be carried forward (but not back) to be deducted against passive income arising in future years. Further, upon the complete disposition of the interest to an unrelated party in a fully taxable transaction, such suspended losses will be available, as described above.

Regarding Partnership income, Limited Partners should generally be entitled to offset their distributive shares of such income with deductions from other passive activities, except to the extent such Partnership income is portfolio income. Since gross income from interest, dividends, annuities, and royalties not derived in the ordinary course of a trade or business is not passive income, a Limited Partner's share of income from royalties, income from the investment of the Partnership's working capital, and other items of portfolio income will not be treated as passive income. In addition, Code Section 469(1)(3) grants the Secretary of the Treasury the authority to prescribe regulations requiring net income or gain from a limited partnership or other passive activity to be treated as not from a passive activity.

C. Publicly Traded Partnerships

Notwithstanding the above, Code Section 469(k) treats net income from PTPs as portfolio income under the PAL rules. Further each partner in a PTP is required to treat any losses from a PTP as separate from income and loss from any other PTP and also as separate from any income or loss from passive activities. *Id.* Losses attributable to an interest in a PTP that are not allowed under the passive activity rules are suspended and carried forward, as described above. Further, upon a complete taxable disposition of an interest in a PTP, any suspended losses are allowed (as described above with respect to the passive loss rules). As noted above, we have opined that the Partnership will not be a PTP.

In the event the Partnership were treated as a PTP, any net income would be treated as portfolio income and each Partner's loss therefrom would be treated as separate from income and loss from any other PTP and also as separate from any income or loss from passive activities. Since the Partnership should not be treated as a PTP, the provisions of Code Section 469(k), in our opinion, will not apply to the Partners in the manner outlined above prior to the time that such Partnership becomes a PTP. However, unlike the PTP rules of Code Section 7704, the passive activity rules of Code Section 469 do not provide an exception for partnerships that pass the 90% test of Code Section 7704. Accordingly, if the Partnership were to be treated as a PTP under the passive activity rules, passive losses could be used only to offset passive income from the Partnership.

ALTERNATIVE MINIMUM TAX

Code Section 55 imposes on noncorporate taxpayers a two-tiered, graduated rate schedule for alternative minimum tax (“AMT”) equal to the sum of (i) 26% of so much of the “taxable excess” as does not exceed $175,000, plus (ii) 28% of so much of the “taxable excess” as exceeds $175,000 (for married individuals filing jointly). Code Section 55(b)(1)(A)(i). “Taxable excess” is defined as so much of the alternative minimum taxable income (“AMTI”) for the taxable year as exceeds the exemption amount. Code Section 55(b)(1)(A)(ii). AMTI is generally defined as the taxpayer’s taxable income, increased or decreased by certain adjustments and items of tax preference. Code Section 55(b)(2).

The exemption amount for noncorporate taxpayers is (i) $62,550 in the case of a joint return or a surviving spouse, (ii) $42,500 in the case of an individual who is not a married individual or a surviving spouse, and (iii) $31,275 in the case of a married individual who files a separate return or an estate or trust. Such amounts are phased out as a taxpayer’s AMTI increases above certain levels. Code Section 55(d)(1) and (3). Individuals subject to the AMT are generally allowed a credit, equal to the portion of the AMT imposed by Code Section 55 arising as a result of deferral preferences for use against the taxpayer’s future regular tax liability (but not the minimum tax liability).

Under the AMT provisions, adjustments and items of tax preference that may arise from a Partner’s acquisition of an interest in the Partnership include the following:

1. Taxpayers which do not meet the definition of an integrated oil company as defined in Code Section 291(b)(4) are not subject to the preference item for “excess IDC.” Code Section 57(a)(2)(E)(i). The benefit of the elimination of the preference is limited in any taxable year to an amount equal to 40 percent of the alternative minimum taxable income for the year computed as if the prior law “excess IDC” preference item has not been eliminated. Code Section 57(a)(2)(E)(ii). Excess IDC is defined as the excess of (i) IDC paid or incurred (other than costs incurred in drilling a nonproductive well) with respect to which a deduction is allowable under Code Section 263(c) for the taxable year over (ii) the amount which would have been allowable for the taxable year if such costs had been capitalized and (I) amortized over a 120 month period beginning with the month in which production from such well begins or (II) recovered through cost

depletion. Code Section 57(a)(2)(B). However, any portion of the IDC to which an election under Code Section 59(e) applies will not be treated as an item of tax preference under Code Section 57(a). Code Section 59(e)(6). With respect to IDC paid or incurred, corporate and individual taxpayers are allowed to make the Code Section 59(e) election and, for regular tax and AMT purposes, deduct such expenditures over the 60 month period beginning with the month in which such expenditure is paid or incurred. Code Section 59(e)(1).

2. The preference item for excess depletion is repealed for other than integrated oil companies. Code Section 57(a)(1).

3. Each Partner's AMTI will be increased (or decreased) by the amount by which the depreciation deductions allowable under Code Sections 167 and 168 with respect to such property exceeds (or is less than) the depreciation determined under the alternative depreciation system using the one hundred fifty percent (150%) declining balance method switching to the straight-line method, when that produces a greater deduction, in lieu of the straight-line method otherwise prescribed by the ADS. Code Section 56(a)(1).

Due to the inherently factual nature of the applicability of the AMT to a Partner, we are unable to express an opinion with respect to such issues. Due to the potentially significant impact of a purchase of Units on an investor's tax liability, investors should discuss the implications of an investment in the Partnership on their regular and AMT liabilities with their tax advisors prior to acquiring Units.

GAIN OR LOSS ON SALE OF PROPERTIES

Gain from the sale or other disposition of property is realized to the extent of the excess of the amount realized therefrom over the property's adjusted basis; conversely, loss is realized in an amount equal to the excess of the property's adjusted basis over the amount realized from such a disposition. Code Section 1001(a). The amount realized is defined as the sum of any money received plus the fair market value of the property (other than money) received. Code Section 1001(b). Accordingly, upon the sale or other disposition of the Partnership properties, the Partners will realize gain or loss to the extent of their pro rata share of the difference between the Partnership's adjusted basis in the property at the time of disposition and the amount realized upon disposition. In the absence of nonrecognition provisions, any gain or loss realized will be recognized for federal income tax purposes.

Gain or loss recognized upon the disposition of property used in a trade or business and held for more than one year will be treated as long term capital gain or as ordinary loss. Code Section 1231(a). Notwithstanding the above, any gain realized may be taxed as ordinary income under one of several "recapture" provisions of the Code or under the characterization rules relating to "dealers" in personal property.

Code Section 1254 generally provides for the recapture of capital gains, arising from the sale of property which was placed in service after 1986, as ordinary income to the extent of the lesser of (i) the gain realized upon sale of the property, or (ii) the sum of (A) all IDC previously deducted and (B) all depletion deductions that reduced the property's basis. Code Section 1254(a)(1).

Ordinary income may also result from the recapture, pursuant to Code Section 1245, of depreciation on the Partnership properties. Such recapture is the amount by which (i) the lower of (A) the recomputed basis of the property, or (B) the amount realized on the sale of the property exceeds (ii) the property's adjusted basis. Code Section 1245(a)(1). Recomputed basis is generally the property's adjusted basis increased by depreciation and amortization deductions previously claimed with respect to the property. Code Section 1245(a)(2).

GAIN OR LOSS ON SALE OF UNITS

It the Units are capital assets in the hands of the Partners, gain or loss realized by any such holders on the sale or other disposition of a Unit will be characterized as capital gain or capital loss. Code Section 1221. Such gain or loss will be a long term capital gain or loss if the Unit is held for more than one year, or a short term capital gain or loss if held for one year or less. However, the portion of the amount realized by a Partner in exchange for a Unit that is attributable to the Partner's share of the Partnership's "unrealized receivables" or "substantially appreciated inventory items" will be treated as an amount realized from the sale or exchange of property other than a capital asset. Code Section 751.

Unrealized receivables are defined in Code Section 751(c) to include " . . . oil [or] gas . . . property . . . to the extent of the amount which would be treated as gain to which section . . . 1245(a) . . . or 1254(a) would apply if . . . such property had been sold by the partnership at its fair market value." A sale by the Partnership of the Partnership's properties could give rise to treatment of the gain thereunder as ordinary income as a result of Code Sections 1245(a) or 1254(a). Accordingly, gain recognized by a Partner on the sale of a Unit would be taxed as ordinary income to the Partner to the extent of his share of the Partnership's gain on property that would be recaptured, upon sale, under those statutes.

Substantially appreciated inventory items are those "inventory items" noted below, the fair market value of which exceeds 120% of the adjusted basis to the partnership of such property, excluding any such inventory property acquired with a principal purpose of avoiding Section 751. Code Section 751(d)(1). Property treated as an "inventory item" for purposes of Code Section 751 includes (i) stock in trade of the partnership or other property of a kind which would properly be included in its inventory if on hand at the end of the taxable year, (ii) property held by the partnership primarily for sale to customers in the ordinary course of its trade or business, and (iii) any other partnership property which would constitute neither a capital asset nor property used in a trade or business under Code Section 1231. Code Sections 751(d)(2) and 1221(1).

Under the aforementioned provisions, a Partner would recognize ordinary income with respect to any deemed sale of assets under Code Section 751; further, this ordinary income may be recognized even if the total amount realized on the sale of a Unit is equal to or less than the Partner's basis in the Unit.

Any partner who sells or exchanges interests in a partnership holding unrealized receivables (which include IDC recapture and other items) or certain inventory items must notify the partnership of such transaction in accordance with Regulations under Code Section 6050K and must attach a statement to his tax return reflecting certain facts regarding the sale or exchange. Regulations promulgated by the Service provide that such notice to the partnership must be given in writing within 30 days of the sale or exchange (or, if earlier, by January 15 of the calendar year following the calendar year in which the exchange occurred), and must include names, addresses, and taxpayer identification numbers (if known) of the transferor and transferee and the date of the exchange. Code Section 6721 provides that persons who fail to furnish this information to the partnership will be penalized $50 for each such failure, or, if such failure is due to intentional disregard to the filing requirement, the person will be penalized the greater of (i) $100 or (ii) 10% of the aggregate amount to be reported. Furthermore, a partnership is required to notify the Service of any sale or exchange of interests of which it has notice, and to report the names and addresses of the transferee and the transferor, along with all other required information. The partnership also is required to provide copies of the information it provides to the Service to the transferor and the transferee.

The tax consequences to an assignee purchaser of a Unit from a Partner are not described herein. Any assignor of a Unit should advise his assignee to consult his own tax advisor regarding the tax consequences of such assignment.

PARTNERSHIP DISTRIBUTIONS

Under the Code, any increase in a partner's share of partnership liabilities, or any increase in such partner's individual liabilities by reason of an assumption by him of partnership liabilities is considered to be a contribution of money by the partner to the partnership. Similarly, any decrease in a partner's share of partnership liabilities or any decrease in such partner's individual liabilities by reason of the partnership's assumption of such individual liabilities will be considered as a distribution of money to the partner by the partnership. Code Section 752(a), (b).

The Partners' adjusted bases in their Units will initially consist of the cash they contribute to the Partnership. Their bases will be increased by their share of Partnership income and additional contributions and decreased by their share of Partnership losses and distributions. To the extent that such actual or constructive distributions are in excess of a Partner's adjusted basis in his Partnership interest (after adjustment for contributions and his share of income and losses of the Partnership), that excess will generally be treated as gain from the sale of a capital asset. In addition, gain could be recognized to a distributee partner upon the disproportionate distribution to a partner of unrealized receivables, substantially appreciated inventory or, in some cases, Code Section 731(c) marketable securities, i.e., actively traded financial instruments, foreign currencies or interests in certain defined properties.

PARTNERSHIP ALLOCATIONS

Allocations—General. Generally, a partner's taxable income is increased or decreased by his ratable share of partnership income or loss. Code Section 701. However, the availability of these losses may be limited by the at risk rules of Code Section 465, the passive activity rules of Code Section 469, and the adjusted basis provisions of Code Section 704(d).

Code Section 704(b) provides that if a partnership agreement does not provide for the allocation of each partner's distributive share of partnership income, gain, loss, deduction, or credit, or if the allocation of such items under the partnership agreement lacks "substantial economic effect," then each partner's share of those items must be allocated "in accordance with the partner's interest in the partnership."

As discussed below, regulations under Code Section 704(b) define substantial economic effect and prescribe the manner in which partners' capital accounts must be maintained in order for the allocations contained in a partnership agreement to be respected. Notwithstanding these provisions, special rules apply with respect to nonrecourse deductions since, under the Treasury Regulations, allocations of losses or deductions attributable to nonrecourse liabilities cannot have economic effect.

The Service may contend that the allocations contained in the Partnership Agreement do not have substantial economic effect or are not in accordance with the Partners' interests in the Partnership and may seek to reallocate these items in a manner that will increase the income or gain or decrease the deductions allocable to a Partner. We are of the opinion that, to the extent provided herein, if challenged by the Service on this matter, the Partners' distributive shares of Partnership income, gain, loss, deduction, or credit will be determined and allocated substantially in accordance with the terms of the Partnership Agreement and have substantial economic effect.

Substantial Economic Effect. Although a partner's share of partnership income, gain, loss, deduction, and credit is generally determined in accordance with the partnership agreement, this share will be determined in accordance with the partner's interest in the partnership (determined by taking into account all facts and circumstances) and not by the partnership agreement if the partnership allocations do not have "substantial economic effect" and if the allocations are not respected under the nonrecourse deduction provisions of the regulations. Code Section 704(b); Reg. Sections 1.704-1(b)(2)(i), 1.704-2.

Treasury regulations provide that:

> *In order for an allocation to have economic effect, it must be consistent with the underlying economic arrangement of the partners. This means that in the event there is an economic benefit or economic burden that corresponds to an allocation, the partner to whom the allocation is made must receive such economic benefit or bear such economic burden.*

Reg. Section 1.704-1(b)(2)(ii). The Regulations further provide that an allocation will have economic effect only if, throughout the full term of the partnership, the partnership agreement provides (i) for the determination and maintenance of partner's capital accounts in accordance with specified rules contained therein, (ii) upon liquidation of the partnership or a partner's interest in the partnership, liquidating distributions are required to be made in accordance with the positive capital account balances of the partners after taking into account all capital account adjustments for the taxable year of the liquidation, and (iii) either (A) a partner with a deficit balance in his capital account following the liquidation is unconditionally obligated to restore the amount of such deficit balance to the partnership by the end of the taxable year of liquidation, or (B) the partnership agreement contains a qualified income offset ("QIO") provision as provided in Reg. Section 1.714-1(b)(2)(ii)(d). Reg. Sections 1.704-1(b)(2)(ii)(b) and 1.704-1(b)(2)(ii)(d).

The capital account maintenance rules generally mandate that each partner's capital account be increased by (i) money contributed by the partner to the partnership, (ii) the fair market value (net of liabilities) of property contributed by the partner to the partnership, and (iii) allocations to the partner of partnership income and gain. Further, such capital account must be decreased by (i) money distributed to the partner from the partnership, (ii) the fair market value (net of liabilities) of property distributed to the partner from the partnership, and (iii) allocations to the partner of partnership losses and deductions. Reg. Section 1.704-1(b)(2)(iv).

Reg. Section 1.714-1(b)(2)(iii) provides that an economic effect of an allocation is "substantial" if there is a reasonable possibility that the allocation will affect substantially the dollar amounts to be received by the partners from the partnership, independent of tax consequences. The economic effect of an allocation is not substantial if:

> *at the time the allocation becomes part of the partnership agreement, (1) the after-tax economic consequences of at least one partner may, in present value terms, be enhanced compared to such consequences if the allocation (or allocations) were not contained in the partnership agreement, and (2) there is a strong likelihood that the after-tax economic consequences of no partner will, in present value terms, be substantially diminished compared to such consequences if the allocation (or allocations) were not contained in the partnership agreement. In determining the after-tax economic benefit or detriment to a partner, tax consequences that result from the interaction of the allocation with such partner's tax attributes that are unrelated to the partnership will be taken into account.*

Reg. 1.704-1(b)(2)(iii)(a).

While the Service stated that it will not rule on whether an allocation provision in a partnership agreement has substantial economic effect, several Technical Advice Memoranda ("TAMs") shed light on the Service's position on such matter. Notwithstanding the potential similarity between TAMs and a taxpayer's particular fact pattern, it should be noted that TAMs may not be used or cited as precedent. Code Section 6110(j)(3), Treas. Reg. Sections 301.6110-2(a) and -7(b). Nevertheless, TAMs do serve to illustrate the Service's position on certain specific cases. The TAMs relating to substantial economic effect focus on the tax avoidance purpose of any such above-described allocations and on the partnership plan for distributions upon liquidation. Illustrative of the Service's approach is TAM 8008054, in which the Service concluded that an allocation to the partners solely of items that the partnership had elected to expense (IDC) had as its principal purpose tax avoidance. The Service suggested that, had the allocation affected the parties' liquidation rights, the allocation would have had substantial economic effect: "In general, substantial economic effect has been found where all allocations of items of income, gain, loss, deduction or credit increase or decrease the respective capital accounts of the partners and distribution of assets made upon liquidation is made in accordance with capital accounts." The ruling noted that the investors "should have been allocated their share of costs over the intangible drilling costs." *Id*. The question whether economic effect is "substantial" is one of fact which may depend in part on the timing of income and deductions and on consideration of the investors' tax attributes unrelated to their investment in Units, and thus is not a question upon which a legal opinion can ordinarily be expressed. However, to the extent the tax brackets of all Partners do not differ at the time the allocation becomes part of the partnership agreement, the economic effect of the allocation provisions should be considered to be substantial.

Code Section 613A(c)(7)(D) requires that the basis of oil and gas properties owned by a partnership be allocated to the partners in accordance with their interests in the capital or income of the partnership. Final Regulations issued under Code Section 613A(c)(7)(D) indicate that such basis must be allocated in accordance with the partners' interests in the capital of the partnership if their interests in partnership income vary over the life of the partnership for any reason other than for reasons such as the admission of a new partner. Reg. Section 1.613A-3(e)(2). The terms “capital” and “income” are not defined in the Code or in the Regulations under Section 613A. The Treasury Regulations under Code Section 704 indicate that if all partnership allocations of income, gain, loss, and deduction (or items thereof) have substantial economic effect, an allocation of the adjusted basis of an oil or gas property among the partners will be deemed to be made in accordance with the partners’ interests in partnership capital or income and will accordingly be recognized.

Pursuant to the Partnership Agreement, (i) allocations will be made as mandated by the Treasury Regulations, (ii) liquidating distributions will be made in accordance with positive capital account balances, and (iii) a “qualified income offset” provision applies. However, while capital will be ultimately owned by the Limited Partners in the Limited Partners’ Percentage and by the General Partner in the General Partner’s Percentage, IDC and other tax items will be allocated 99% to the Limited Partners and 1% to the General Partner until the Limited Partner Capital Contributions are entirely expended and thereafter 100% to the General Partner. Except with respect to those excess allocations, under the Partnership Agreement, the basis in oil and gas properties will be allocated in proportion to each Partner’s respective share of the costs which entered into the Partnership’s adjusted basis for each depletable property. Such allocations of basis appear reasonable and in compliance with the Treasury Regulations under Section 704. Nevertheless, the Service may contend that the allocation to the Limited Partners of a percentage of Partnership IDC in excess of the Limited Partners’ Percentage or the allocation to the General Partner of other tax items in excess of the General Partner’s Percentage is invalid and may reallocate such excess IDC or other items to the other Partners. Any such reallocation could increase a Limited Partner’s tax liability. However, no assurance can be given, and we are unable to express an opinion, as to whether any special allocation of an item which is dependent upon basis in an oil and gas property will be recognized by the Service.

Nonrecourse Deductions. As noted above, an allocation of loss or deduction attributable to nonrecourse liabilities of a partnership cannot have economic effect because only the creditor bears the economic burden that corresponds to such an allocation. Nevertheless the Temporary Regulations provide a test under which certain allocations of nonrecourse deductions will be deemed to be in accordance with the partners’ interests in the partnership.

Nonrecourse deduction allocations will be deemed to be made in accordance with partners partnership interests if, and only if, four requirements are satisfied. First, the partners’ capital accounts must be maintained properly and the distribution of liquidation proceeds must be in accordance with the partners’ capital account balances. Second, beginning in the first taxable year in which there are nonrecourse deductions, and thereafter throughout the full term of the partnership, the partnership agreement must provide for allocation of nonrecourse deductions among the partners in a manner that is reasonably consistent with allocations which have substantial economic effect of some other significant partnership item attributable to the property securing nonrecourse liabilities of the partnership. Third, beginning in the first taxable year of the partnership in which the partnership has nonrecourse deductions or makes a distribution of proceeds of a nonrecourse liability that are allocable to an increase in minimum gain, and thereafter throughout the full term of the partnership, the partnership agreement must contain a "minimum gain chargeback." A partnership agreement contains a "minimum gain chargeback" if, and only if, it provides that, subject to certain exceptions, in the event there is a net decrease in partnership minimum gain during a partnership taxable year, the partners must be allocated items of partnership income and gain for that year equal to each partner's share of the net decrease in partnership minimum gain during such year. A partner's share of the net decrease in partnership minimum gain is the amount of the total net decrease multiplied by the partner's percentage share of the partnership's minimum gain at the end of the immediately preceding taxable year. A partner's share of any decrease in partnership minimum gain resulting from a revaluation of partnership property (which would not cause a minimum gain chargeback) equals the increase in the partner's capital account attributable to the revaluation to the extent the reduction in minimum gain is caused by such revaluation. Similar rules apply with regard to partner nonrecourse liabilities and associated deductions. The fourth requirement of the nonrecourse allocation test provides that all other material allocations and capital account adjustments under the partnership agreement must be recognized under the general allocation requirements of the regulations under IRC Section 704(b).

Under the Treasury Regulations, partners generally share nonrecourse liabilities in accordance with their interests in partnership profits. However, the Treasury Regulations generally require that nonrecourse liabilities be allocated among the partners first to reflect the partners' share of minimum gain and Code Section 704(c) minimum gain. Any remaining nonrecourse liabilities are generally to be allocated in proportion to the partners' interests in partnership profits.

The Partnership Agreement contains a minimum gain chargeback. Further, the Partnership Agreement provides for the allocation of nonrecourse liabilities and deductions attributable thereto among the Partners first, in accordance with their respective shares of partnership minimum gain (within the meaning of Reg. Section 1.704-2(b)(2)); second, to the extent of each such Partner's gain under Code Section 704(c) if the Partnership were to dispose of (in a taxable transaction) all Partnership property subject to one or more nonrecourse liabilities of the Partnership in full satisfaction of such liabilities and for no other consideration; and third, in accordance with the Partners' proportionate shares in the Partnership's profits. Reg. Section 1.752-3. For this purpose, the Partnership Agreement provides for the allocation of excess nonrecourse deductions in the Limited Partners' Percentage to the Limited Partners and in the General Partner's Percentage to the General Partner.

Retroactive Allocations. To prevent retroactive allocations of partnership tax attributes to partners entering into a partnership late in the tax year, Code Section 706(d) provides that a partner's distributive share of such attributes is to be determined by the use of methods prescribed by the Secretary of the Treasury which take into account the varying interests of the partners during the taxable year. The Partnership Agreement provides that each Partner's allocation of tax items other than "allocable cash basis items" is to be determined under a method permitted by Code Section 706(d) and the regulations thereunder.

PROFIT MOTIVE

The existence of economic, non-tax motives for entering into the Transaction is essential if the Partners are to obtain the tax benefits associated with an investment in the Partnership.

Code Section 183(a) provides that where an activity entered into by an individual is not engaged in for profit, no deduction attributable to that activity will be allowed except as provided therein. Should it be determined that a Partner's activities with respect to the Transaction fall within the "not for profit" ambit of Code Section 183, the Service could disallow all or a portion of the deductions and credits generated by the Partnership's activities.

Code Section 183(d) generally provides for a presumption that an activity is entered into for profit within the meaning of the statute where gross income from the activity exceeds the deductions attributable to such activity for three or more of the five consecutive taxable years ending with the taxable year in question. At the taxpayer's election, such presumption can relate to three or more of the taxable years in the 5-year period beginning with the taxable year in which the taxpayer first engages in the activity. Whether an activity is engaged in for profit is determined under Code Sections 162 (relating to trade or business deductions) and 212(1) and (2) (relating to income producing deductions) except insofar as the above-described presumption applies. Reg. Section 1.183-1(a).

To establish that he is engaged in either a trade or business or an income producing activity, a Partner must be able to prove that he is engaged in the Transaction with an "actual and honest profit objective," *Fox v. Commissioner*, 80 T.C. 972, 1006 (1983), *aff'd sub nom., Barnard v. Commissioner*, 731 F.2d 230 (4th Cir. 1984), and that his profit objective is *bona fide. Bessenyey v. Commissioner*, 45 T.C. 261, 274 (1965), *aff'd*, 379 F.2d 252 (2d Cir. 1967), *cert. denied*, 389 U.S. 931 (1967). The inquiry turns on whether the primary purpose and intention of the Partner in engaging in the activity is, in fact, to make a profit apart from tax considerations. *Hager v. Commissioner*, 76 T.C. 759, 784. Such objective need not be reasonable, only honest, and the question of objective is to be determined from all the facts and circumstances. *Sutton v. Commissioner*, 84 T.C. 210 (1985), *aff'd*, 788 F.2d 695 (11th Cir. 1986). Among the factors that will normally be considered are: (i) the manner in which the taxpayer carries on the activity, (ii) the expertise of the taxpayer or his advisors, (iii) the time and effort expended by the taxpayer in carrying on the activity, (iv) whether an expectation exists that the assets used in the activity may appreciate in value, (v) the success of the taxpayer in carrying on similar or dissimilar activities, (vi) the taxpayer's history of income or losses with respect to the activity, (vii) the amount of occasional profits, if any, which are earned, and (viii) the financial status of the taxpayer. Treas. Reg. Section 1.183-2(b). Where application of such factors to a particular activity is difficult, however, the Court will consider the totality of the circumstances instead. *Estate of Baron v. Commissioner*, 83 T.C. 542 (1984), *aff'd* 798 F.2d 65 (2d Cir. 1986).

As noted, the issue is one of fact to be resolved not on the basis of any one factor but on the basis of all the facts and circumstances. Reg. Section 1.183-2(b). Greater weight is given to objective facts than the parties' mere statements of their intent. *Siegel v. Commissioner*, 78 T.C. 659, *Engdahl v. Commissioner*, 72 T.C. 659 (1979). Nevertheless, the Courts have recognized, in applying Code Section 183, that "a taxpayer has the right to engage in a venture which has economic substance even though his motivation in the early years of the venture may have been to obtain a deduction to offset taxable income." *Lemmen v. Commissioner*, 77 T.C. 1326, 1346 (1981), *acq*., 1983-1 C.B. 1.

Due to the inherently factual nature of a Partner's intent and motive in engaging in the Transaction, we do not express an opinion as to the ultimate resolution of this issue in the event of a challenge by the Service. Partners must, however, seek to make a profit from their activities with respect to the Transaction beyond any tax benefits derived from those activities or risk losing those tax benefits.

TAX AUDITS

Subchapter C of Chapter 63 of the Code provides that administrative proceedings for the assessment and collection of tax deficiencies attributable to a partnership must be conducted at the partnership, rather than the partner, level. Partners will be required to treat Partnership items of income, gain, loss, deduction, and credit in a manner consistent with the treatment of each such item on the Partnership's returns unless such Partner files a statement with the Service identifying the inconsistency. If the Partnership is audited, the tax treatment of each item will be determined at the Partnership level in a unified partnership proceeding. Conforming adjustments to the Partners' own returns will then occur unless such partner can establish a basis for inconsistent treatment (subject to waiver by the Service).

The General Partner will be designated the "tax matters partner" ("TMP") for the Partnership and will receive notice of the commencement of a Partnership proceeding and notice of any administrative adjustments of Partnership items. The TMP is entitled to invoke judicial review of administrative determinations and to extend the period of limitations for assessment of adjustments attributable to Partnership items. Each Partner will receive notice of the administrative proceedings from the TMP and will have the right to participate in the administrative proceeding pursuant to tax requirements of Reg. Section 301.6223(g) unless the Partner waives such rights.

The Code provides that, subject to waiver, partners will receive notice of the administrative proceedings from the Service and will have the right to participate in the administrative proceedings. However, the Code also provides that if a partnership has 100 or more partners, the partners with less than a 1% profits interest will not be entitled to receive notice from the Service or participate in the proceedings unless they are members of a "notice group" (a group of partners having in the aggregate a 5% or more profits interest in the partnership that requires the Service to send notice to the group and that designates one of their members to receive notice). Any settlement agreement entered into between the Service and one or more of the partners will be binding on such partners but will not be binding on the other partners, except that settlement by the TMP may be binding on certain partners, as described below. The Service must, on request, offer consistent settlement terms to the partners who had not entered into the earlier settlement agreement. If a partnership has more than 100 partners, the TMP is empowered under the Code to enter into binding settlement agreements on behalf of the partners with a less than 1% profits interest unless the partner is a member of a notice group or notifies the Service that the TMP does not have the authority to bind the partner in such a settlement.

The costs incurred by a Partner in responding to an administrative proceeding will be borne solely by such Partner.

PENALTIES

Under IRC Section 6662, a taxpayer will be assessed a penalty equal to twenty percent (20%) of the portion of an underpayment of tax attributable to negligence, disregard of a rule or regulation or a substantial understatement of tax. "Negligence" includes any failure to make a reasonable attempt to comply with the tax laws. IRC Section 6662(c). The regulations further provide that a position with respect to an item is attributable to negligence if it lacks a reasonable basis. Reg. Section 1.6662-3(b)(1). Negligence is strongly indicated where, for example, a partner fails to comply with the requirements of IRC Section 6662, which requires that a partner treat partnership items on its return in a manner that is consistent with the treatment of such items on the partnership return. Reg. Section 1.6662-3(b)(1)(iii). The term "disregard" includes any careless, reckless or intentional disregard of rules or regulations. Reg. Section 1.6662-3(b)(2). A taxpayer who takes a position contrary to a revenue ruling or a notice will be subject to a penalty for intentional disregard if the contrary position fails to possess a realistic possibility of being sustained on its merits. Reg. Section 1.6562-3(b)(2). An "understatement" is defined as the excess of the amount of tax required to be shown on the return of the taxable year over the amount of the tax imposed that is actually shown on the return, reduced by any rebate. IRC Section 6662(d)(2)(A). An understatement is “substantial” if it exceeds the greater of ten percent (10%) of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 in the case of certain corporations). IRC Section 6662(d)(1)(A) and (B).

Generally, for tax returns with due dates (determined without regard to extensions) after December 31, 1993, the amount of an understatement is reduced by the portion thereof attributable to (i) the tax treatment of any item by the taxpayer if there is or was substantial authority for such treatment, or (ii) any item if the relevant facts affecting the item’s tax treatment are adequately disclosed in the return or in a statement attached to the return, and there is a reasonable basis for the tax treatment of such item by the taxpayer. IRC Section 6662(d). Disclosure will generally be adequate if made on a properly completed Form 8275 (Disclosure Statement) or Form 8275R (Regulation Disclosure Statement). Reg. Section 1.6662-4(f). However, in the case of “tax shelters,” there will be a reduction of the understatement only to the extent it is attributable to the treatment of an item by the taxpayer with respect to which there is or was substantial authority for such treatment and only if the taxpayer reasonably believed that the treatment of such item by the taxpayer was more likely than not the proper treatment. Moreover, under the Uruguay Round Table Agreements Act, a corporation must generally satisfy a higher standard to avoid a substantial understatement penalty in the case of a tax shelter. IRC Section 6662(d)(2)(C)(ii). The term “tax shelter” is defined for purposes of Code Section 6662 as a partnership or other entity, any investment plan or arrangement, or any other plan or arrangement, the principal purpose of which is the avoidance or evasion of federal income tax. IRC Section 6662(d)(2)(C)(ii). It is important to note that this definition of “tax shelter” differs from that contained in Code Sections 461 and 6111, as discussed above. A tax shelter item includes an item of income, gain, loss, deduction, or credit that is directly or indirectly attributable to a partnership that is formed for the principal purpose of avoiding or evading federal income tax. The existence of substantial authority is determined as of the time the taxpayer’s return is filed or on the last day of the taxable year to which the return relates and not when the investment is made. Reg. Section 1.6662-4(d)(3)(iv)(C). Substantial authority exists if the weight of authorities supporting a position is substantial compared with the weight of authorities supporting contrary treatment. Reg. Section 1.6662-4(d)(3)(i). Relevant authorities include statutes, Regulations, court cases, revenue rulings and procedures, and Congressional intent. However, among other things, conclusions reached in legal opinions are not considered authority. Reg. Section 1.6662-4(d)(3)(iii). The Secretary may waive all or a portion of the penalty imposed under Code Section 6662 upon a showing by the taxpayer that there was reasonable cause for the understatement and that the taxpayer acted in good faith. IRC Section 6664(d).

Although not anticipated by the General Partner, there may not be substantial authority for one or more reporting positions that the Partnership may take in its federal income tax returns. In such event, if the Partnership does not disclose or if it fails to adequately disclose any such position, or if such disclosure is deemed adequate but it is determined that there was no reasonable basis for the tax treatment of such a partnership item, the penalty will be imposed with respect to any substantial understatement determined to have been made, unless the provisions of the Treasury Regulations pertaining to waiver of the penalty become final and the Partnership is able to show reasonable cause and good faith in making the understatement as specified in such provisions. If the Partnership makes a disclosure for the purposes of avoiding the penalty, the disclosure is likely to result in an audit of such return and a challenge by the Service of such position taken.

If it were determined that a Partner had underpaid tax for any taxable year, such Partner would have to pay the amount of underpayment plus interest on the underpayment from the date the tax was originally due. The interest rate on underpayments is determined by the Service based upon the federal short term rate of interest (as defined in Code Section 1274(d)) plus 3%, or 5% for large corporate underpayments, and is compounded daily. The rate of interest is adjusted monthly. In addition, Temporary Regulations provide that tax motivated transactions include, among other items, certain overstatements of the value of property on a return, losses disallowed by reason of the at-risk limitation any use of an accounting method that may result in a substantial distortion of income for any period, and any deduction disallowed for an activity not entered into for profit. The determination of those transactions to be considered “tax-motivated transactions” is to be made by taking into account the ratio of tax benefits to cash invested, the method of promoting the transaction, and other relevant transactions. Thus, in the event an audit of the Partnership’s or of a Partner’s tax return results in a substantial underpayment of tax by such Partner due to an investment in the Units, such Partner may be required to pay interest on such underpayment determined at the higher interest rate.

A partnership, for federal income tax purposes, is required to file an annual informational tax return. The failure to properly file such a return in a timely fashion, or the failure to show on such return all information under the Code to be shown on such return, unless such failure is due to reasonable cause, subjects the partnership to civil penalties under the Code in an amount equal to $50 per month multiplied by the number of partners in the partnership, up to a maximum of $250 per partner per year. In addition, upon any willful failure to file a partnership information return, a fine or other criminal penalty may be imposed on the party responsible for filing the return.

As noted above under the heading “IMPORTANT LIMITATIONS ON TAX ASPECTS — LIMITED SCOPE OPINION DISCLAIMER,” the Letter was not intended or written to be used, and cannot be used, for the purpose of avoiding penalties that may be imposed by the Service with respect to any federal tax issues not addressed therein.

ACCOUNTING METHODS AND PERIODS

The Partnership will use the accrual method of accounting and will select the calendar year as its taxable year.

As discussed above, a taxpayer using the accrual method of accounting will recognize income when all events have occurred which fix the right to receive such income and the amount thereof can be determined with reasonable accuracy. Deductions will be recognized when all events which establish liability have occurred and the amount thereof can be determined with reasonable accuracy. However, all events which establish liability are not treated as having occurred prior to the time that economic performance occurs. Code Section 461(h).

All partnerships are required to conform their tax years to those of their owners; i.e., unless the partnership establishes a business purpose for a different tax year, the tax year of a partnership must be (i) the taxable year of one or more of its partners who have an aggregate interest in partnership profits and capital of greater than 50%, (ii) if there is no taxable year so described, the taxable year of all partners having interests of 5% or more in partnership profits or capital, or (iii) if there is no taxable year described in (i) or (ii), the calendar year. Code Section 706. Until the taxable years of the Partners can be identified, no assurance can be given that the Service will permit the Partnership to adopt a calendar year.

STATE AND LOCAL TAXES

The opinions expressed herein are limited to issues of federal income tax law and do not address issues of state or local law. Investors are urged to consult their tax advisors regarding the impact of state and local laws on an investment in the Partnership.

PROPOSED LEGISLATION AND REGULATIONS

There can be no assurances that subsequent changes in the tax laws (through new legislation, court decisions, Service pronouncements, Treasury regulations, or otherwise) will or will not occur that may have an impact, adverse or positive, on the tax effect and consequences of this Transaction, as described above.

We express no opinion as to any federal income tax issue or other matter except those set forth or confirmed above.

We hereby consent to the filing of this opinion as Exhibit B to the Memorandum and to all references to our firm in the Memorandum.

Sincerely,

Conner & Winters, LLP

EX-21 3 dex21.htm SUBSIDIARIES OF THE REGISTRANT

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

All the companies listed below are included in the company's consolidated financial statements. Except as otherwise indicated below, the Company has 100% direct or indirect ownership of, and ultimate voting control in, each of these companies. The list is as of December 31, 2006 and excludes 100% owned subsidiaries which are primarily inactive and taken singly, or as a group, do not constitute significant subsidiaries:

Subsidiary	State or Province of Incorporation	Percentage Owned
Unit Drilling Company	Oklahoma	100%
Unit Petroleum Company	Oklahoma	100%
Superior Pipeline Company, L.L.C.	Texas	100%

EX-23.1 4 dex231.htm CONSENT OF REGISTERED PUBLIC ACCOUNTING FIRM

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (File No.'s 333-104165, 333-83551, 333-99979 and 333-128213) and Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-53542, 33-64323, 333-38166, 333-39584, 333-135194 and 333-137857) of Unit Corporation of our report dated March 1, 2007 relating to the financial statements, financial statement schedule, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 1, 2007

EX-23.2 5 dex232.htm CONSENT OF RYDER SCOTT COMPANY, L.P.

Exhibit 23.2

March 1, 2007

CONSENT OF RYDER SCOTT COMPANY, L.P.

We consent to incorporation by reference in the Registration Statements (File Nos. 333-83551, 333-99979, 333-104165 and 333-128213) on Form S-3, and the Registration Statements (File Nos. 33-19652, 33-44103, 33-49724, 33-64323, 33-53542, 333-38166, 333-39584, 333-135194, 333-137857 and 333-137857) on Form S-8 of Unit Corporation of the reference to our reports for Unit Corporation, which appears in the December 31, 2006 annual report on Form 10-K of Unit Corporation.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.

Houston, Texas
March 1, 2007

EX-31.1 6 dex311.htm SECTION 302 CEO CERTIFICATION

Exhibit 31.1

302 CERTIFICATIONS

I, Larry D. Pinkston, certify that:

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

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes is accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/S/ LARRY D. PINKSTON

Larry D. Pinkston
Chief Executive Officer and Director

EX-31.2 7 dex312.htm SECTION 302 CFO CERTIFICATION

Exhibit 31.2

302 CERTIFICATIONS

I, David T. Merrill, certify that:

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

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes is accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/s/ DAVID T. MERRILL

David T. Merrill
Chief Financial Officer and Treasurer

EX-32.1 8 dex321.htm SECTION 906 CEO AND CFO CERTIFICATIONS

Exhibit 32.1

CERTIFICATION
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (A) AND (B) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Unit Corporation a Delaware corporation (the "Company"), does hereby certify, to such officer's knowledge, that:

The Annual Report on Form 10-K for the year ended December 31, 2006 (the "Form 10-K") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2006 and December 31, 2005 and for the years ended December 31, 2006, 2005 and 2004.

Dated: March 1, 2007

By: /s/ LARRY D. PINKSTON

Larry D. Pinkston
Chief Executive Officer

Dated: March 1, 2007

By: /s/ DAVID T. MERRILL

David T. Merrill
Chief Financial Officer and Treasurer

The foregoing certification is being furnished solely pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code) and is not being filed as part of the Form 10-K or as a separate disclosure document.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Unit Corporation and will be retained by Unit Corporation and furnished to the Securities and Exchange Commission or its staff on request.