F O R M 1 0-K

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the fiscal year ended December 31, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from _____ to _____

[Commission File Number 1-9260]

U N I T C O R P O R A T I O N

(Exact Name of Registrant as Specified in its Charter)

Delaware	73-1283193
(State of Incorporation)	(I.R.S. Employer Identification No.)

1000 Kensington Tower 7130 South Lewis Tulsa, Oklahoma	74136
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, Including Area Code (918) 493-7700

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.20 per share	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes _X_ No ___

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

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

Yes _X_ No ___

Aggregate Market Value of the Voting Stock Held By Non-affiliates on June 30, 2003 - $669,121,359

Number of Shares of Common Stock Outstanding on March 11, 2004 - 45,709,568

DOCUMENTS INCORPORATED BY REFERENCE

1. Portions of Registrant's Proxy Statement with respect to the Annual Meeting of Stockholders to be held May 5, 2004 are incorporated by reference in Part III.

Exhibit Index - See Page 113

FORM 10-K
UNIT CORPORATION

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2003

PART I

Item 1. Business and Item 2. Properties
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OUR BUSINESS

Through our two principal wholly owned subsidiaries, Unit Drilling Company and Unit Petroleum Company, we

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

We were founded in 1963 as a contract drilling company.

Our executive offices are at 1000 Kensington Tower, 7130 South Lewis, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700.

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

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

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

OUR LAND CONTRACT DRILLING BUSINESS

General. Using our 88 drilling rigs, our wholly owned subsidiary, Unit Drilling Company, drills onshore natural gas and oil wells for a wide range of customers. Our drilling operations are mainly in the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and in the East Texas and Rocky Mountain regions.

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

	Year Ended December 31,				
	1999	2000	2001	2002	2003
Number of Rigs Owned at End of Period	47.0	50.0	55.0	75.0	88.0
Average Number of Rigs Owned During Period	37.3	47.0	51.8	61.6	75.9
Average Number of Rigs Utilized	23.1	39.8	46.3	39.1	62.9
Utilization Rate (1)	62%	85%	90%	63%	83%
Average Revenue Per Day (2)	$6,582	$7,432	$9,879	$8,285	$7,972
Total Footage Drilled (Feet in 1000's)	2,211	3,650	4,008	3,829	6,580
Number of Wells Drilled	197	316	361	318	530

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

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

Acquisitions. On December 8, 2003, we acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, a U.S. land drilling company located in Borger, Texas for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the three years following the acquisition. SerDrilco, a private, Tulsa-based drilling company, has been operating in the Anadarko Basin in the Texas Panhandle for more than 50 years. Equipment acquired through the SerDrilco acquisition includes 12 rigs which range from 650 horsepower to 1,700 horsepower with depth capacities rated from 6,500 feet to 18,000 feet, a fleet of 12 trucks and a district office and equipment yard in and near Borger, Texas.

During November of 2003, we completed the construction of a 1,500 horsepower diesel electric rig with a depth capacity of 20,000 feet. The rig is operating for our Mid-Continent Division in Western Oklahoma.

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

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

The following table shows the current distribution of our rigs as of March 1, 2004:

Region	Contracted Rigs	Idle Rigs	Total Rigs	Average Rated Drilling Depths(ft)
Anadarko Basin	59	1	60	16,000
Arkoma Basin	7	--	7	16,000
East Texas and Gulf Coast	13	--	13	18,000
Rocky Mountains	8	--	8	22,000

At present, we do not have a shortage of drilling rig related equipment. However, at any given time, our ability to use all of our rigs is dependent on a number of conditions, including the availability of qualified labor, drilling supplies and equipment as well as demand. As utilization in the industry has improved throughout most of 2003, it has become increasingly difficult to find additional qualified labor for our drilling rigs. More opportunities for field employees to find work in our regions of operation has increased the competition for qualified labor among drilling contractor. If rig utilization remains at its current rate or increases, we expect this competition for qualified labor will continue to have an adverse effect on our drilling operations in the future and result in higher operating costs.

Types of Drilling Contracts We Work Under. Our drilling contracts are predominantly obtained through competitive bidding and are for a single well. Terms and payment rates vary depending on the nature and duration of the work, the equipment and services supplied and other matters. We pay certain operating expenses, including wages of drilling personnel,

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

Under turnkey contracts we may incur losses if we underestimate the costs to drill the well or if unforeseen events occur. To date, we have not experienced significant losses in performing turnkey contracts. In 2003, we drilled six turnkey wells and turnkey revenue represented 1% of our contract drilling revenues as compared to 15 turnkey wells and turnkey revenue representing 4% for 2002. We did not have any turnkey contracts in progress at December 31, 2003. Because market conditions as well as the desires of our customers determine the use of turnkey contracts, we can't predict whether the portion of drilling conducted on a turnkey basis will increase or decrease in the future.

Customers. During 2003, 10 customers accounted for approximately 53% of our total contract drilling revenues. Chesapeake Operating, Inc. was our largest customer providing 15% of our total contract drilling revenues. Our contract drilling operations drilled 43 wells in 2003 which were operated by our exploration and production segment. These wells also have working interests which are owned by limited partnerships for which we acted as general partner. As required by the Securities and Exchange Commission, the profit received by our contract drilling segment of $841,000 and $1,883,000 during 2002 and 2003, respectively, was used to reduce the carrying value of our oil and natural gas

properties rather than being included in our profits in current operations.

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

OUR OIL AND NATURAL GAS BUSINESS

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

The following table presents certain information regarding the company's oil and gas operations as of December 31, 2003.

			Average Daily Production	
Property/Area	Number of Gross Wells	Number of Net Wells	Mcf	Bbls
Western Division (includes the Rocky Mountain Region, New Mexico, Western and Southern Texas and the Gulf Coast Region)	981	254.44	13,600	880
East Division (consists principally of the Appalachian Region, Arkansas, parts of East Texas and Eastern Oklahoma	553	146.04	17,100	40
Central Division (consist principally of Kansas, the rest of Oklahoma and Texas Panhandle Areas)	1,794	427.91	25,800	480
Canada	65	1.63	100	--
Total	3,393	830.02	56,600	1,400

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

Acquisition. On January 30, 2004, we acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash. PetroCorp Incorporated explored and developed oil and natural gas properties primarily in Texas and Oklahoma. Approximately 84% of the oil and natural gas properties acquired in the acquisition are located in the Mid-Continent and Permian basins, while 6% are located in the Rocky Mountains and 10% are located in the Gulf Coast basin. The acquired properties increase our reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide additional locations for development drilling in the future. With the acquisition of PetroCorp Incorporated we also entered into a new $150 million credit facility to replace our existing loan agreement as more fully discussed in Note 4 to the Consolidated Financial Statements in Item 8 hereof.

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

	Year Ended December 31,					
	2001		2002		2003	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
-						
Exploratory:						
Oil	1	.01	--	--	--	--
Natural gas	8	3.60	2	0.50	3	1.84
Dry	5	4.46	5	2.00	1	1.00
	14	8.07	7	2.50	4	2.84
Development:						
Oil	6	1.06	4	1.91	5	2.13
Natural gas	87	33.51	68	33.25	120	46.22
Dry	18	10.80	17	14.21	20	10.38
	111	45.37	89	49.37	145	58.73
Total	125	53.44	96	51.87	149	61.57

	Year Ended December 31,					
	2001		2002		2003	
	Gross	Net	Gross	Net	Gross	Net
Oil and Natural Gas Wells Producing or Capable of Producing:						
-						
Oil - USA	786	279.06	790	273.34	803	280.40
Oil - Canada	--	--	--	--	--	--
Gas - USA	2,188	457.38	2,449	524.45	2,525	547.99
Gas - Canada	64	1.60	65	1.63	65	1.63
Total	3,038	738.04	3,304	799.42	3,393	830.02

On March 1, 2004, we were participating in the drilling of 14 gross (7.1 net) wells in the United States.

Cost incurred for development drilling includes $9.7 million, $10.8 million and $20.4 million in 2001, 2002 and 2003, respectively, to develop booked proved undeveloped 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
2001:				
USA	567,731	155,890	110,489	69,229
Canada	39,040	976	7,273	3,636
Total	606,771	156,866	117,762	72,865
2002:				
USA	585,313	166,397	142,764	79,911
Canada	39,040	976	5,441	3,360
Total	624,353	167,373	148,205	83,271
2003(1):				
USA	600,872	173,674	159,663	90,862
Canada	39,040	976	4,162	2,624
Total	639,912	174,650	163,825	93,486

(1) Approximately 80% of the net undeveloped acres are covered by leases that will expire in each of the years 2004 - 2006 unless drilling or production otherwise extends the terms of the leases.

Future development costs estimated to be expended to develop our proved undeveloped reserves in the USA in 2004, 2005 and 2006, as disclosed in our December 31, 2003 reserve report, are $33.8 million, $29.3 million and $3.3 million, respectively. No similar future development costs have been estimated for Canada.

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

	Year Ended December 31,		
	2001	2002	2003
Average Sales Price per Barrel of Oil Produced:			
USA price before hedging	$ 23.58	$ 21.54	$ 26.94
Effect of hedging	0.04	--	--
USA price including hedging	$ 23.62	$ 21.54	$ 26.94
Canada	$ --	$ --	$ --
Average Sales Price per Mcf of Natural Gas Produced:			
USA price before hedging	$ 3.89	$ 2.87	$ 4.87
Effect of hedging	0.11	--	--
USA price including hedging	$ 4.00	$ 2.87	$ 4.87
Canada price before hedging	$ 4.21	$ 2.11	$ 4.49
Effect of hedging	--	--	--
Canada price including hedging	$ 4.21	$ 2.11	$ 4.49
Oil Production (Mbbls):			
USA	492	473	516

Canada	--	--	--
Total	492	473	516
Natural Gas Production (MMcf):			
USA	18,819	18,927	20,610
Canada	45	41	38
Total	18,864	18,968	20,648

Average Production Cost per Equivalent Mcf:			
USA	$ 0.86	$ 0.79	$ 0.90
Canada	$ 0.51	$ 0.60	$ 0.56

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

	Year Ended December 31,		
	2001	2002	2003
Oil (Mbbls):			
USA	4,343	4,096	5,141
Canada	--	--	--
Total	4,343	4,096	5,141
Natural gas (MMcf):			
USA	227,865	244,494	253,542
Canada	389	317	650
Total	228,254	244,811	254,192

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

Additional Information. Further information relating to oil and natural gas operations can be found in Notes 1, 10, 12 and 13 of Notes to Consolidated Financial Statements set forth in Item 8 hereof.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for natural gas and oil significantly affect our revenues, operating results, cash flow and future rate of growth. Because natural gas makes up the biggest part of our oil and natural gas reserves as well as the focus of most of the drilling work we do for others, changes in natural gas prices have a larger impact on us than changes in oil prices. Historically, oil and natural gas prices have been volatile, and we expect them to continue to be so.

The following table shows the highest and lowest average monthly natural gas and oil price we received by quarter for each of the periods indicated:

	Average Monthly Natural Gas Price per Mcf		Average Monthly Oil Price per Bbl	
QUARTER	High	Low	High	Low
2001:				
First	$ 9.35	$ 4.82	$ 28.13	$ 26.20
Second	$ 4.92	$ 3.69	$ 26.63	$ 23.78

Third	$ 3.45	$ 2.05	$ 24.66	$ 23.35
Fourth	$ 2.42	$ 2.08	$ 18.99	$ 16.28
2002:				
First	$ 2.11	$ 1.87	$ 19.60	$ 15.58
Second	$ 3.03	$ 2.98	$ 23.44	$ 22.07
Third	$ 2.97	$ 2.47	$ 23.57	$ 23.01
Fourth	$ 3.95	$ 3.35	$ 25.59	$ 21.90
2003:				
First	$ 8.38	$ 4.18	$ 32.72	$ 27.74
Second	$ 5.59	$ 4.22	$ 27.10	$ 24.56
Third	$ 4.63	$ 4.36	$ 27.41	$ 23.62
Fourth	$ 5.06	$ 4.06	$ 27.48	$ 26.31

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

- political conditions in oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- the domestic and foreign supply of oil and natural gas;
- the level of consumer demand;
- United States storage levels of natural gas; . the ability to transport to key markets;

- weather conditions;
- domestic and foreign government regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

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

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. Natural gas prices started to fall in February, 2001. As a result, we started to receive less demand for our drilling rigs starting in October, 2001 and the rates received for our rigs also began to fall until they reached a low of $7,275 per day in February of 2003. As natural gas and oil prices once again began to rise during the last half of 2002 and in the second quarter of 2003 through the remainder of the year both demand for our rigs and dayrates began to improve. In December 2003, the average dayrate of the 76 drilling rigs that we owned prior to the SerDrilco acquisition was approximately $8,200 per day. The 12 rigs added in December 2003 had a dayrate of approximately $7,500 resulting in an average dayrate of $8,130 for all 88 rigs in December 2003. Since short-term and long-term trends in oil and natural gas prices affect the demand for our rigs, future demand and dayrates received for our drilling services is uncertain.

COMPETITION

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

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

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 10 oil and gas limited partnerships. Four were formed for investment by third parties and six (the employee partnerships) were formed to allow employees of Unit and its subsidiaries and directors of Unit to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984, 1985 and 1986. An additional third party partnership, the 1979 Oil and Gas Limited Partnership was dissolved on July 1, 2003. Employee partnerships have been formed for each year beginning with 1984.

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 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 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.

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

comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate such conflicts.

These partnerships are further described in Notes 1 and 7 to Consolidated Financial Statements set forth in Item 8 hereof.

EMPLOYEES

As of March 1, 2004, we had approximately 1,882 employees in our land contract drilling operations, 70 employees in our oil and natural gas operations and 60 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

OPERATING AND OTHER RISKS

Our drilling operations are subject to the many hazards inherent in the drilling industry, including injury or death to personnel, blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather. Our exploration and production operations are also subject to many of these similar risks. Any of

these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others.

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

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

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;

- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or drilling crews and the delivery of equipment.

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

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

GOVERNMENTAL REGULATIONS

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

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

Our sales of natural gas will be affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of

natural gas. These changes are intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines is required to divest to a marketing affiliate, which operates separately from

the transporter and in direct competition with all other merchants. As a result of the various omnibus rulemaking proceedings in the late 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, the interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, the FERC expanded the impact of open access regulations to intrastate commerce.

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

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

In the past, Congress has been very active in the area of natural gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation and the promotion of competition in the natural gas industry. Thus, in addition to "first sales" deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There are other legislative proposals pending in the Federal and State legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the

ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

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

experienced by the oil pipeline industry. We are not able to predict with certainty what effect, if any, these relatively new federal regulations or the periodic review of the index by the FERC will have on us.

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

SAFE HARBOR STATEMENT

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

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

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

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

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

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

In order to provide a more thorough understanding of the possible effects

of some of these influences on any forward-looking statements made by us, the following discussion outlines certain factors that in the future could cause our consolidated results for 2004 and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

Commodity Prices. The prices we receive for our oil and natural gas production have a direct impact on our revenues, profitability and our cash flow as well as our ability to meet our projected financial and operational goals. The prices for natural gas and crude oil are heavily dependent on a number of factors beyond our control, including the demand for oil and/or natural gas; current weather conditions in the continental United States

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

Based on our 2003 production, a $.10 per Mcf change in what we receive for our natural gas production would result in a corresponding $160,300 per month ($1,923,600 annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price would have a $40,000 per month ($480,000 annualized) change in our pre-tax operating cash flow. During 2003, substantially all of our natural gas and crude oil volumes were sold at market responsive prices.

In order to reduce our exposure to short-term fluctuations in the price of oil and natural gas, we sometimes enter into hedging or swap arrangements. Our hedging or swap arrangements apply to only a portion of our production and provide only partial price protection against declines in oil and natural gas prices. These hedging or swap arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices and are more fully discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 hereof.

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

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

- the effects of regulations by governmental agencies;
- future oil and natural gas prices;

- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

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

The information regarding discounted future net cash flows included in this document is not necessarily the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves 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 also are affected by the following factors:

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

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

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally

requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if we exceed the ceiling, even if prices are depressed for only a short period of time. We may be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

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

Debt and Bank Borrowing. We have experienced and expect to continue to experience substantial working capital needs due to the growth in our drilling operations and our active exploration and development programs. Historically, we have funded our working capital needs through a combination of internally generated cash flow, equity financing and borrowings under our bank loan agreement. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2003, our long-term debt outstanding was $400,000. With the acquisition of PetroCorp Incorporated (as further discussed in Note 12 of the Notes to Consolidated Financial Statements) on January 30, 2004, we signed a new loan agreement with a total loan commitment of $150 million, but we elected to limit the amount available for borrowing under our bank loan agreement to $120 million in order to reduce our financing costs. After the PetroCorp acquisition our outstanding debt on February 18, 2004 was $90.0 million.

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

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

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

The amount of our existing debt as well as our future debt is, to a large extent, a function of the costs associated with the projects we undertake at any given time and the cash flow we receive. Generally, our normal operating costs are those associated with the drilling of oil and natural gas wells, the acquisition of producing properties, and the costs associated with the maintenance or expansion of our drilling rig fleet. To some extent, these costs, particularly the first two items, are discretionary and we maintain a degree of control regarding the timing and/or the need to incur the same. However, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to acquire a large producing property package or the need to replace a costly rig component due to an unexpected loss, which could force us to incur increased debt above that which we had expected or forecasted. Likewise, if our cash flow should prove to be insufficient to cover our current cash requirements we would need to increase our debt either through bank borrowings or otherwise.

Executive Officers. The table below and accompanying footnotes set forth certain information concerning each of our executive officers as of March 15, 2004.

NAME	AGE	POSITION HELD
John G. Nikkel	69	Chairman of the Board since August 1, 2003 Director since 1983 Chief Executive Officer since July 1, 2001 President and Chief Operating Officer from 1983 to August 1, 2003
Larry D. Pinkston	49	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	46	Senior Vice President since December 2002 General Counsel and Corporate Secretary

		since January 1987
Philip M. Keeley(1)	62	Senior Vice President, Exploration and Production since 1983
David T. Merrill	43	Chief Financial Officer and Treasurer since February 24,2004 Vice President of Finance from August 2003 to February 24,2004

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(1) Mr. Keeley has announced his plans to retire effective April, 15, 2004

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

Mr. Pinkston joined Unit in December, 1981. He had served as Corporate Budget Director and Assistant Controller prior to being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President of the company as well as its Chief Financial Officer. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer. He was elected as director of the company by the Board in January, 2004. Mr. Pinkston holds the offices of President and Chief Operating Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

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

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

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

Item 3. Legal Proceedings

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

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

No matters were submitted to our security holders during the fourth quarter of 2004.

PART II

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

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

	2002		2003	
QUARTER	High	Low	High	Low
First	$ 18.60	$ 10.24	$ 21.99	$ 16.30
Second	$ 20.93	$ 16.01	$ 23.39	$ 19.14
Third	$ 19.25	$ 13.65	$ 22.60	$ 18.68
Fourth	$ 20.44	$ 16.71	$ 24.51	$ 18.40

On March 1, 2004 there were 1,763 record holders of our common stock.

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

Item 6. Selected Financial Data

	Year Ended December 31,				
	1999 (1)	2000	2001	2002	2003
	(In thousands except per share amounts)				
Revenues	$ 102,352	$ 201,264	$ 259,179	$ 187,636	$ 302,584
Income Before Change in Accounting Principle	$ 3,048	$ 34,344	$ 62,766	$ 18,244	$ 48,864
Net Income	$ 3,048	$ 34,344	$ 62,766	$ 18,244	$ 50,189
Income Before Change in Accounting Principle per Common Share:					
Basic	$ 0.10	$ 0.96	$ 1.75	$ 0.47	$ 1.12
Diluted	$ 0.10	$ 0.95	$ 1.73	$ 0.47	$ 1.12
Net Income per Common Share:					
Basic	$ 0.10	$ 0.96	$ 1.75	$ 0.47	$ 1.15
Diluted	$ 0.10	$ 0.95	$ 1.73	$ 0.47	$ 1.15
Total Assets	$ 295,567	$ 346,288	$ 417,253	$ 578,163	$ 712,925
Long-Term Debt	$ 67,239	$ 54,000	$ 31,000	$ 30,500	$ 400
Other Long-Term Liabilities	$ 2,325	$ 3,597	$ 4,110	$ 5,439	$ 17,893
Cash Dividends Per Common Share	$ --	$ --	$ --	$ --	$ --

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

See Item 7. Management's Discussion of Financial Condition and Results of Operations for a review of 2001, 2002 and 2003 activity.

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

FINANCIAL CONDITION AND LIQUIDITY

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Summary. Our financial condition and liquidity depends on the cash flow from our two principal subsidiaries and borrowings under our bank loan agreement. Our cash flow is influenced mainly by the prices we receive for our natural gas production, the demand for and the dayrates we receive for our drilling rigs and, to a lesser extent, the prices we receive for our oil production. At December 31, 2003, we had cash totaling $598,000 and we had borrowed $400,000 under our loan agreement.

Over the last six months of 2003 the average monthly natural gas price we received excluding the impact of hedging, ranged from $4.06 in October to $5.06 in December and the average Nymex Henry Hub daily price for the same time period ranged from $4.79 to $7.00. With the average Nymex contract settle price for the next twelve months at $5.40 on February 18, 2004, we expect natural gas prices to remain at levels that will increase demand for our rigs and provide upward movement on the rates we receive for our contract drilling services. There is, however, no assurance that these prices will actually be sustained throughout 2004.

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

Working Capital	$ 20,931,000
Long-Term Debt.	$ 400,000
Shareholders' Equity.	$ 515,768,000
Ratio of Long-Term Debt to Total Capitalization.	--%
Net Income.	$ 50,189,000
Net Cash Provided by Operating Activities.	$ 121,712,000

The following table summarizes certain operating information for the years ended December 31, 2002 and 2003:

	2002	2003	Percent Change
Oil Production (Bbls)	473,000	516,000	9%
Natural Gas Production (Mcf)	18,968,000	20,648,000	9%
Average Oil Price Received.	$ 21.54	$ 26.94	25%
Average Natural Gas Price Received.	$ 2.87	$ 4.87	70%
Average Number of Our Drilling Rigs in Use During the Period	39.1	62.9	61%

In December 2003, we acquired SerDrilco Incorporated for $35.0 million in cash. To finance the acquisition we sold 2.0 million shares of common stock for net proceeds of $42.1 million.

Our Bank Loan Agreement. At December 31, 2003, we had a $100 million bank loan agreement consisting of a revolving credit facility through May 1, 2005 and a term loan thereafter, maturing on May 1, 2008. On January 30, 2004, in conjunction with our acquisition of PetroCorp Incorporated, we replaced our loan agreement with a revolving credit facility totaling $150 million having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount. Although the current value of our assets under the latest loan value computation supported the full $150 million, we elected to set the loan commitment at $120 million in order to reduce financing costs since we are charged a commitment fee of .375 of 1% on the amount available but not borrowed. We paid 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 loan. Following the acquisition of PetroCorp Incorporated our borrowings were $90.0 million on February 18, 2004.

The loan value under our current credit facility is subject to a semi-annual re-determination on May 10 and November 10 of each year, beginning May 10, 2004. The calculation is based primarily on the sum of a percentage of the discounted future value of our oil and natural gas reserves, as determined by the banks. In addition, an amount representing a part of the value of our drilling rig fleet, limited to $20 million, is added to the loan value. Provisions are also in the agreement which allow for one requested special re-determination of the borrowing base by either the lender or us between each scheduled re-determination date if conditions warrant such a request.

At our election, any portion of the debt outstanding may be fixed at a Eurodollar Rate for 30, 60, 90 or 180 day terms. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar Rate option applies may be repaid upon three days prior notice to the Administrative Agent. Interest on the Eurodollar Rate is computed at the Eurodollar 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 Eurodollar 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 February 18, 2004, all of our $90.0 million debt was subject to the Eurodollar Rate.

The loan agreement includes prohibitions against:

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

The loan agreement also requires that at the end of each quarter:

- consolidated net worth of at least $350 million,
- a current ratio (as defined in the loan agreement) of not less than 1 to 1 and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the loan agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

Hedging. Periodically we hedge the prices we will receive for a portion of our future natural gas and oil production. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow. We entered into a collar contract covering approximately 25% of our daily oil production for January and February of 2001. The collar had a floor of $26.00 per barrel and a ceiling of $33.00 per barrel and we received $0.86 per barrel for entering into the transaction. During the first quarter of 2001, our oil hedging transaction yielded an increase in our oil revenues of $17,200.

During the second quarter of 2001, we entered into a natural gas collar contract for approximately 36% of our June and July 2001 production, at a floor price of $4.50 and a ceiling price of $5.95. During the third quarter of 2001, we entered into two natural gas collar contracts for approximately 38% of our September through November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling of $3.68 and the other contract had a ceiling of $4.25. During the year of 2001, the collar contracts increased natural gas revenues by $2,030,000.

On April 30, 2002, we entered into a collar contract covering approximately 19% of our natural gas production for the periods of April 1, 2002 through October 31, 2002. The collar had a floor of $3.00 and a ceiling of $3.98. During the year of 2002, our natural gas hedging transactions increased natural gas revenues by $40,300. We did not have any hedging transactions outstanding at December 31, 2002.

During the first quarter of 2003, we entered into two collar contracts covering approximately 40% of our natural gas production for the periods of April 1, 2003 through September 30, 2003. One collar had a floor of $4.00 and a ceiling of $5.75 and the other collar had a floor of $4.50 and a ceiling of $6.02. We also entered into two collar contracts covering approximately 25% of our oil production for the periods of May 1, 2003 through December 31, 2003. One collar had a floor of $25.00 and a ceiling of $32.20 and the other collar had a floor of $26.00 and a ceiling of $31.40. During the year of 2003, the collar contracts decreased natural gas revenues by $6,000 and oil revenues by $5,000. We did not have any hedging transactions outstanding at December 31, 2003.

In January 2004, we entered into a natural gas collar covering approximately 14% of our estimated natural gas production. The transaction covers the periods of April through October of 2004 and has a floor of $4.50 and a ceiling of $6.76. We also entered into an oil hedge covering approximately 40% of our estimated oil production. The transaction covers the periods of February through December of 2004 and has an average price of $31.40.

Self-Insurance. We are self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits. The exposure (i.e. our deductible or retention) per occurrence ranges from $200,000 for general liability to $1 million for rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain claims. There is no assurance that such coverage will adequately protect us against liability from all potential consequences. Following the acquisition of SerDrilco we have continued to use its ERISA governed occupational injury benefit plan to cover its employees in lieu of covering them under an insured Texas workers' compensation plan.

Impact of Prices for Our Oil and Natural Gas. With the acquisition of PetroCorp Incorporated (as further discussed in Note 12 of the Notes to Consolidated Financial Statements), natural gas comprises 86% of our total oil and natural gas reserves. Before the acquisition, natural gas comprised 89% of our 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 2003, a $.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $160,300 per month ($1,923,600 annualized) change in our pre-tax operating cash flow. Our 2003 average natural gas price was $4.87 compared to an average natural gas price of $2.87 for 2002. A $1.00 per barrel change in our oil price would have a $40,000 per month ($480,000 annualized) change in our pre-tax operating cash flow based on our production in 2003. Our

2003 average oil price was $26.94 compared with an average oil price of $21.54 received in 2002.

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

We sell most of our natural gas production to third parties under month-to-month contracts. Several of these buyers have experienced financial complications resulting from the recent investigations into the energy trading industry. The long-term implications to the energy trading business, as well as to oil and natural gas producers, because of these investigations remains, to be determined. We continue to evaluate the information available to us about our buyers and try to reduce any possible future adverse impact to us. Presently we believe that our buyers will be able to perform their commitments to us. For 2003, purchases by Cinergy Marketing & Trading LP accounted for approximately 17% of our oil and natural gas revenues while purchases by Centerpoint Energy Gas accounted for approximately 16% of our oil and natural gas revenues. We own a 16.7% limited partner interest in Eagle Energy Partners I LP, whose purchases, which are competitively marketed, accounted for 6% of our oil and natural gas revenues in 2003. We have increased our sales to Eagle Energy Partners I LP

since we first started selling natural gas to them in August, 2003. For the period August through December 2003 Eagle has purchased 16% of our oil and natural gas revenues and they marketed approximately 37% of the natural gas volumes we sold for ourselves and third parties during the same five month period.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when to incur such costs. We drilled 149 wells (61.57 net wells) in 2003 compared to 96 wells (51.87 net wells) in 2002. Our total capital expenditures for oil and natural gas exploration and acquisitions in 2003 totaled $73.3 million excluding capitalized cost for the recording of the plugging liability associated with our wells. Based on current prices, we plan to drill an estimated 165 to 175 wells in 2004 and total capital expenditures for oil and natural gas exploration and acquisitions is planned to be around $95 million.

Contract Drilling. Our drilling work is subject to many factors that influence the number of rigs we have working as well as the costs and revenues associated with such work. These factors include competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our rigs and our ability to supply

the equipment needed. We have not encountered major difficulty in hiring and keeping rig crews, but such shortages have occurred periodically in the past. If demand for drilling rigs increases rapidly in the future, shortages of experienced personnel may limit our ability to increase the number of rigs we could operate.

Most of our contract drilling fleet is targeted to the drilling of natural gas wells, so changes in natural gas prices influence the demand for our drilling rigs and the prices we can charge for our contract drilling services. In the last half of 1999 and throughout 2000, as oil and natural gas prices increased, we experienced a big increase in demand for our rigs. Demand continued to increase until the end of the third quarter of 2001 and reached a high when 52 of our rigs were working in July 2001. Because of declining natural gas prices throughout 2001, demand for our rigs dropped significantly in the fourth quarter of 2001 and stabilized with between 30 and 35 rigs operating in the first half of 2002. The rates received for our rigs also began to fall until they reached a low of $7,275 per day in February of 2003. Natural gas and oil prices once again began to rise during the last half of 2002 and in the second quarter of 2003 through the remainder of the year both demand for our rigs and dayrates continued to improve. In December 2003 the average dayrate on the 75 rig fleet owned by us throughout 2003 was approximately $8,200 per day and the 12 Service rigs added in December 2003 had a dayrate of approximately $7,500 making the average dayrate for the 88 rig fleet $8,130 in December 2003. The average use of our rigs in 2003 was 62.9 rigs (83%) compared with 39.1 rigs (63%) for 2002. Our average dayrate in 2003 was $7,808 compared to $7,716 for 2002. Based on the average utilization of our rigs in 2003, a $100 per day change in dayrates has a $6,290 per day ($2,296,000 annualized) change in our pre-tax operating cash flow. Utilization and dayrates for our drilling rigs will depend mainly on the price of natural gas.

Our contract drilling subsidiary provides drilling services for our exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts we have entered into with unrelated third parties. During 2003, we drilled 43 wells for our exploration and production subsidiary. Per regulations provided by the Securities and Exchange Commission, the profit received by our contract drilling segment of $841,000 and $1,883,000 during 2002 and 2003, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

Drilling Acquisitions and Capital Expenditures. On December 8, 2003, we acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the three years following the acquisition. 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 an equipment yard in and near Borger, Texas. For our contract drilling operations during 2003, we incurred $71.9 million in capital

expenditures, which includes $35.0 million in cash and $10.9 million for goodwill resulting from

deferred tax liabilities recorded in connection with the SerDrilco acquisition. For the year 2004, we have budgeted capital expenditures of approximately $30 million for our contract drilling operations.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner for 10 oil and natural gas partnerships which were formed privately and publicly. The partnership's revenues and costs are shared under formulas prescribed in each limited partnership agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by management to be reasonable. During 2001, 2002 and 2003, the total paid to us for all of these fees was $1,107,000, $929,000 and $873,000, respectively. We expect the fees to be about the same in 2004. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

We own a 40% equity interest in Superior Pipeline Company LLC, an Oklahoma Limited Liability Company. Superior is a natural gas gathering and processing company. Our investment, including our share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets in our accompanying balance sheet. During 2003, Superior Pipeline Company LLC purchased $3.3 million of our natural gas production and paid $64,000 for our natural gas liquids. We paid this company $39,000 for gathering and compression services.

We also own a 16.7% limited partnership interest in Eagle Energy Partnership I, L.P. ("Eagle"), carried at cost, for $2.5 million. 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. Eagle was marketing approximately 46% of the natural gas volumes we sell for ourselves and third parties in December 2003 and during February 2004 they are marketing 48%.

Contractual Commitments. We have the following contractual obligations at December 31, 2003:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank Debt(1)	$ 400	$ --	$ --	$ 400	$ --
Retirement Agreement(2)	1,650	300	600	600	150
Operating Leases(3)	3,555	719	1,424	954	458
Total Contractual Obligations	$ 5,605	$ 1,019	$ 2,024	$ 1,954	$ 608

(1) See Previous Discussion in Management Discussion and Analysis

regarding bank debt. The obligation is presented in accordance with the terms of the loan agreement signed on January 30, 2004.

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

(3) We lease office space in Tulsa and Woodward, Oklahoma and Houston, Texas under the terms of operating leases expiring through January 31, 2010 along with leasing space on short-term commitments to stack excess rig equipment and production inventory. In the first quarter of 2003, we renegotiated our rental agreement for the Tulsa office reducing the price per square foot while adding additional space and lengthening the term of the agreement to January 31, 2010.

At December 31, 2003, we also have the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Amount of Commitment Expiration Per Period			
Other Commitments	Total Amount Committed or Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred Compensation Agreement(1)	$ 1,829	Unknown	Unknown	Unknown	Unknown
Separation Benefit Agreement(2)	$ 2,545	$ 412	Unknown	Unknown	Unknown
Plugging Liability(3)	$ 11,994	$ 303	$ 481	$ 882	$ 10,328
Gas Balancing Liability(4)	$ 1,191	Unknown	Unknown	Unknown	Unknown
Repurchase Obligations(5)	Unknown	Unknown	Unknown	Unknown	Unknown

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

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

(3) On January 1, 2003 we adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of

long-lived assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled or acquired).

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

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2004, with a subsidiary of ours serving as General Partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, upon the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $1,000 and $106,000 in 2002 and 2003, respectively, for such limited partners' interests. No repurchases were made in 2001.

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

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed or if we have large downward revisions in our estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil and natural gas prices on December 31, 2003 ($5.67 per Mcf for natural gas and $32.52 per barrel for

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

The value of our oil and natural gas reserves is used to determine the borrowing base under our loan agreement with our banks. This amount is affected by both price changes and the measurement of reserve volumes. Oil and natural gas reserves cannot be measured exactly. Our estimate of oil and natural gas reserves require extensive judgments of our reservoir engineering data and are less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves.

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

Drilling equipment, transportation equipment and other property and

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

We recognize revenues and expense generated from "daywork" drilling contracts as the services are performed, since we do not bear the risk of completion of the well. 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. 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 can be reasonably determined, however, any profit is recorded only at the time the well is finished. The costs of uncompleted drilling contracts include expenses incurred to date on "footage" or "turnkey" contracts, which are still in process at the end of the period, and are included in other current assets.

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

NEW ACCOUNTING PRONOUNCEMENTS
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On January 1, 2003 we adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. We own oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling the plugging liabilities.

The effect of this change increased net property, plant and equipment by $13.0 million and liabilities, including deferred tax liabilities, by $11.7 million at January 1, 2003 and decreased net income for the year ended December 31, 2003 by $148,000 ($0.00 per share). The financial statements for the year ended December 31, 2002 have not been restated and the cumulative effect of the change of $1.3 million net of tax ($0.03 per share) is shown as a one-time addition to income in the first quarter of 2003.

On January 17, 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB 51" ("FIN 46"). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. FIN 46, as amended, was effective for us in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, did not have an impact on our financial position or results of operations. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, we will have to adopt FIN 46, as amended, in the quarter ending March 31, 2004. We are still evaluating FIN 46 with regard to these types of entities in which we have an ownership interest, primarily our oil and gas partnerships and our equity investment in Superior pipeline. FIN 46 may require full consolidation of these entities which would increase our total assets with an offsetting minority interest for the percentage not owned by Unit. There will be no net impact to our results of operations from the adoption of FIN 46.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (FAS 142) were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the notes to our financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, we, like many other oil and gas companies, have included oil and gas extraction rights as part of the oil and gas properties, even after FAS 141 and 142 became effective.

Our results of operations and cash flows would not be affected, since these oil and gas mineral extraction rights would continue to be amortized in accordance with full cost accounting rules.

At December 31, 2002 and 2003, we had undeveloped leaseholds of approximately $13.2 million and $14.8 million, respectively that would be classified on our balance sheets as "intangible undeveloped leasehold" and

developed leaseholds of an estimated $18.1 million and $24.6 million, respectively that would be classified as "intangible developed leasehold" if the interpretations were applied. This classification would require us to make the disclosures set forth under FAS 142 related to these interests.

We intend to continue to classify our oil and gas mineral extraction rights as tangible oil and gas properties until further guidance is provided.

RESULTS OF OPERATIONS

2003 versus 2002

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

	2002	2003	Percent Change
Total Revenue	$ 187,636,000	$ 302,584,000	61%
Income Before Change in Accounting Principle	$ 18,244,000	$ 48,864,000	168%
Net Income	$ 18,244,000	$ 50,189,000	175%
Oil and Natural Gas:			
Revenue	$ 67,959,000	$ 116,609,000	72%
Average natural gas price (Mcf)	$ 2.87	$ 4.87	70%
Average oil price (Bbl)	$ 21.54	$ 26.94	25%
Natural gas production (Mcf)	18,968,000	20,648,000	9%
Oil production (Bbl)	473,000	516,000	9%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.04	$ 1.14	10%
Depreciation, depletion and amortization ($346,000 write off of interest in Shenandoah in 2002)	$ 23,338,000	$ 27,343,000	17%
Drilling:			
Revenue	$ 118,173,000	$ 183,146,000	55%
Percentage of revenue from daywork contracts	91%	98%	
Average number of rigs in use	39.1	62.9	61%
Average dayrate on daywork contracts	$ 7,716	$ 7,808	1%
Depreciation	$ 14,684,000	$ 23,644,000	61%
General and Administrative Expense	$ 8,712,000	$ 9,222,000	6%
Interest Expense	$ 973,000	$ 693,000	(29%)
Average Interest Rate	3.0%	2.2%	(27%)
Average Long-Term Debt Outstanding	$ 24,771,000	$ 20,722,000	(16%)

Oil and natural gas revenues and net income were all positively affected by the higher prices we received for both our oil and natural gas during 2003 as compared to 2002. Production for both oil and natural gas was also up between the comparative years. Total operating cost increased primarily from higher

gross production taxes resulting from higher revenues. Total depreciation, depletion and amortization ("DD&A") on our oil and natural gas properties increased due to higher production volumes and an increase in the DD&A rate in 2003, which resulted from higher development drilling cost per equivalent Mcf.

Operator demand for our rigs increased gradually throughout 2003 as natural gas prices increased in 2003 versus 2002 and resulted in higher rig use and dayrates for our rigs. Higher dayrates were offset by higher rig expense as we experienced a 121% increase in ad valorem taxes on our rigs and a 175% increase in worker's compensation expense. We expect both of these expenses, along with increased demand for quality labor within the industry, to keep upward pressure on rig costs throughout 2004. Approximately 2% of our total drilling revenues in 2003 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. Nine percent of our total drilling revenues came from footage and turnkey contracts in 2002. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002 and additional rig use.

General and administrative expense was higher in 2003 due to an increase in general liability insurance, director and officer insurance and increased corporate administrative cost. Our total interest expense is lower due to lower interest rates and a substantial reduction in our average long-term debt. Income tax expense increased 202% primarily due to a 180% increase in income before income taxes. Our effective tax rate for 2002 was 34.4% versus 37.2% in 2003. The impact of higher statutory depletion and other permanent differences reduced by the impact of state income taxes was the cause for the lower effective tax rate in 2002.

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

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

	2001	2002	Percent Change
Total Revenue	$ 259,179,000	$ 187,636,000	(28%)
Net Income	$ 62,766,000	$ 18,244,000	(71%)
Oil and Natural Gas:			
Revenue	$ 90,237,000	$ 67,959,000	(25%)
Average natural gas price (Mcf)	$ 4.00	$ 2.87	(28%)
Average oil price (Bbl)	$ 23.62	$ 21.54	(9%)
Natural gas production (Mcf)	18,864,000	18,968,000	1%
Oil production (Bbl)	492,000	473,000	(4%)
Depreciation, depletion and amortization rate (Mcfe)	$ 0.91	$ 1.04	14%
Depreciation, depletion and amortization (includes $2,083,000 and $346,000 write off of interest in Shenandoah in 2001 and 2002, respectively)	$ 22,116,000	$ 23,338,000	6%
Drilling:			
Revenue	$ 167,042,000	$ 118,173,000	(29%)
Percentage of revenue from daywork contracts	99%	91%	
Average number of rigs in use	46.3	39.1	(16%)
Average dayrate on daywork			

contracts	$ 10,044	$ 7,716	(23%)
Depreciation	$ 13,888,000	$ 14,684,000	6%
General and Administrative Expense	$ 8,476,000	$ 8,712,000	3%
Interest Expense	$ 2,818,000	$ 973,000	(65%)
Average Interest Rate	5.7%	3.0%	(47%)
Average Long-Term Debt Outstanding	$ 44,995,000	$ 24,771,000	(45%)

Oil and natural gas revenues, net income were all negatively affected by lower prices received for both oil and natural gas during 2002 compared to 2001. Production in equivalent Mcf was almost the same in 2002 as in 2001. Total operating cost decreased due to lower gross production taxes resulting from lower revenues. Total DD&A on our oil and natural gas properties increased due to the increase in the DD&A rate in 2002, which resulted from higher development drilling cost per equivalent Mcf. The increase would have been larger, but included in 2001 DD&A was the write down of our investment in Shenandoah Resources LTD. In 2001 Shenandoah started experiencing financial difficulties and its stock price declined, so we took a write down in our investment of $2.1 million to reduce the carrying value to the market value of Shenandoah's stock. In August 2002, the assets of Shenandoah were liquidated for the benefit of the secured creditors and, as a result, our remaining investment of $346,000 in Shenandoah was written off.

Reduced natural gas prices, especially in the fourth quarter of 2001 and the first quarter of 2002, caused decreases in operator demand for contract drilling rigs within our working area and resulted in lower rig use and dayrates for our rigs. Total drilling operating costs were relatively unchanged between the two years. Approximately 9% of our total drilling revenues in 2002 came from footage and turnkey contracts, which had profit margins lower than our daywork contracts. One percent of our total drilling revenues came from footage and turnkey contracts in 2001. Contract drilling depreciation increased due to the acquisition of 20 rigs in August of 2002. The increase was partially offset by lower rig use.

General and administrative expense was higher in 2002 due to increases in labor cost, insurance expense and outside contract services. In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense plus accrued interest will be paid in $25,000 monthly payments starting in July 2003 and continuing through June 2009. Our total interest expense is lower due to lower interest rates along with a substantial reduction in our long-term debt. Income tax expense decreased 73% primarily due to a 72% decrease in income before income taxes.

Item 7a. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil and natural gas production. The price we receive is primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, prices we received for our oil and natural gas production fluctuated and such fluctuation is expected to continue. The price of natural gas also effects the demand for our rigs and the amount we can charge for the use of the rigs. Based on our 2003 production, a $.10 per Mcf

change in what we are paid for our natural gas production would result in a corresponding $160,300 per month ($1,923,600 annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $40,000 per month ($480,000 annualized) change in our pre-tax operating cash flow.

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

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the JPMorgan Chase Prime Rate or the Eurodollar Rate. At our election, borrowings under our revolving credit facility may be fixed at the Eurodollar Rate for periods up to 180 days. Historically, we have not utilized any financial instruments, such as interest rate swaps, to manage our exposure to increases in interest rates. However, we may use financial instruments in the future should our assessment of future interest rates warrant there use. Based on our average outstanding long-term debt in 2003, a 1% change in the floating rate would change our annual pre-tax cash flow by approximately $207,000.

Item 8. Financial Statements and Supplementary Data

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2002	2003
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 497	$ 598
Accounts receivable (less allowance for doubtful accounts of $1,203 and $1,223)	33,912	58,807
Materials and supplies	8,794	8,023
Income tax receivable	3,602	112
Prepaid expenses and other	4,594	5,202
Total current assets	51,399	72,742
Property and Equipment:		
Drilling equipment	369,777	424,321
Oil and natural gas properties, on the full cost method:		
Proved Properties	449,226	528,110
Undeveloped Leasehold not being amortized	16,024	17,486
Transportation equipment	6,856	9,828
Other	9,906	14,535
	851,789	994,280
Less accumulated depreciation, depletion, amortization and impairment	341,031	385,219
Net property and equipment	510,758	609,061

Goodwill	12,794	23,722
Other Assets	3,212	7,400
Total Assets	$ 578,163	$ 712,925

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - CONTINUED

	As of December 31,	
	2002	2003
	(In thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current portion of long-term debt and other liabilities (Note 4)	$ 1,465	$ 1,015
Accounts payable	21,119	32,871
Accrued liabilities	11,921	15,921
Contract advances	27	2,004
Total current liabilities	34,532	51,811
Long-Term Debt (Note 4)	30,500	400
Other Long-Term Liabilities (Note 4)	5,439	17,893
Deferred Income Taxes (Note 5)	86,320	127,053
Commitments and Contingencies (Note 9)		
Shareholders' Equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	--	--
Common stock, $.20 par value, 75,000,000 shares authorized, 43,339,400 and 45,592,012 shares issued, respectively	8,668	9,117
Capital in excess of par value	264,180	307,938
Retained earnings	148,524	198,713
Total shareholders' equity	421,372	515,768
Total Liabilities and Shareholders' Equity	$ 578,163	$ 712,925

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2001	2002	2003
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 167,042	$ 118,173	$ 183,146
Oil and natural gas	90,237	67,959	116,609
Other	1,900	1,504	2,829
Total revenues	259,179	187,636	302,584

Expenses:			
Contract drilling:			
Operating costs	91,006	91,338	138,762
Depreciation	13,888	14,684	23,644
Oil and natural gas:			
Operating costs	22,196	20,795	25,169
Depreciation, depletion, amortization and impairment	22,116	23,338	27,343
General and administrative	8,476	8,712	9,222
Interest	2,818	973	693
Total expenses	160,500	159,840	224,833
Income Before Income Taxes and Change in Accounting Principle	98,679	27,796	77,751
Income Tax Expense:			
Current	5,609	(3,469)	--
Deferred	30,304	13,021	28,887
Total income taxes	35,913	9,552	28,887
Income Before Change in Accounting Principle	62,766	18,244	48,864
Cumulative Effect of Change in Accounting Principle (Net of Income Tax of $811)	--	--	1,325
Net Income	$ 62,766	$ 18,244	$ 50,189

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME - CONTINUED

	Year Ended December 31,		
	2001	2002	2003
	(In thousands except per share amounts)		
Basic Earnings Per Common Share:			
Income before change in accounting principle	$ 1.75	$ 0.47	$ 1.12
Cumulative effect of change in accounting principle net of income tax	--	--	0.03
Net income	$ 1.75	$ 0.47	$ 1.15
Diluted Earnings Per Common Share:			
Income before change in accounting principle	$ 1.73	$ 0.47	$ 1.12
Cumulative effect of change in accounting principle net of income tax	--	--	0.03
Net income	$ 1.73	$ 0.47	$ 1.15
Pro Forma Amounts Assuming Retroactive Application of Change in Accounting Principle:			

Net income	$ 62,662	$ 18,115
Basic earnings per share	$ 1.74	$ 0.47
Diluted earnings per share	$ 1.73	$ 0.46

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2001, 2002 and 2003

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehen-sive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2001	$ 7,154	$ 139,872	$ 67,514	$ --	$ --	$ 214,540
Net Income	--	--	62,766	--	--	62,766
Activity in employee compensation plans (237,923 shares)	47	2,105	--	--	--	2,152
Purchase of treasury shares (30,000 shares)	--	--	--	--	(296)	(296)
Other comprehen-sive income (net of tax of $771 and $771):						
Change in value of cash flow deriva-tive instru-ments used as cash flow hedges	--	--	--	1,258	--	1,258
Adjustment reclas-ification - deriva-tive settle-ments	--	--	--	(1,258)	--	(1,258)
Balances, December 31, 2001	$ 7,201	$ 141,977	$130,280	$ --	$ (296)	$ 279,162

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY - CONTINUED
Year Ended December 31, 2001, 2002 and 2003

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehen-sive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2002	$ 7,201	$ 141,977	$130,280	$ --	$ (296)	$ 279,162
Net Income	--	--	18,244	--	--	18,244
Activity in employee compensation plans (113,133 shares)	23	1,156	--	--	296	1,475
Issuance of stock for acquisition (7,220,000 shares)	1,444	121,047	--	--	--	122,491
Other comprehen-sive income (net of tax of $15 and $15):						
Change in value of cash flow deriva-tive instr-uments used as cash flow hedges	--	--	--	25	--	25
Adjustment reclas-ification - deriva-tive settle-ments	--	--	--	(25)	--	(25)
Balances, December 31, 2002	$ 8,668	$ 264,180	$148,524	$ --	$ --	$ 421,372

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY - CONTINUED
Year Ended December 31, 2001, 2002 and 2003

	Common Stock	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehen-sive Income	Treasury Stock	Total
	(In thousands except share amounts)					
Balances, January 1, 2003	$ 8,668	$ 264,180	$148,524	$ --	$ --	$ 421,372
Net Income	--	--	50,189	--	--	50,189
Activity in employee compensation plans (252,612 shares)	49	2,018	--	--	--	2,067
Issuance of 2,000,000 shares of common stock)	400	41,740	--	--	--	42,140
Other comprehen-sive income (net of tax of $3 and $3):						
Change in value of cash flow deriva-tive instru-ments used as cash flow hedges	--	--	--	(4)	--	(4)
Adjustment reclas-ifica-tion - deriva-tive settle-ments	--	--	--	4	--	4
Balances, December 31, 2003	$ 9,117	$ 307,938	$198,713	$ --	$ --	$ 515,768

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2001	2002	2003

	(In thousands)		
Cash Flows From Operating Activities:			
Net Income	$ 62,766	$ 18,244	$ 50,189
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, amortization and impairment	36,642	38,657	51,783
Equity in net earnings of unconsolidated investments	(1,148)	(745)	(1,516)
Loss (gain) on disposition of assets	(56)	(69)	51
Employee stock compensation plans	2,873	1,165	1,415
Bad debt expense	--	603	645
Plugging liability - cumulative effect - net of accretion	--	--	(1,624)
Deferred tax expense	30,304	13,021	28,887
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	6,334	(43)	(25,540)
Materials and supplies	(1,556)	(3,436)	771
Prepaid expenses and other	(3,533)	2,365	4,240
Accounts payable	(155)	1,784	6,148
Accrued liabilities	929	(350)	4,286
Contract advances	61	(213)	1,977
Other liabilities	(440)	(436)	--
Net cash provided by operating activities	133,021	70,547	121,712

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS - CONTINUED

	Year Ended December 31,		
	2001	2002	2003
	(In thousands)		
Cash Flows From Investing Activities:			
Capital expenditures (including producing property and contract drilling acquisitions)	$(108,339)	$ (75,225)	$(131,162)
Proceeds from disposition of property and equipment	2,631	1,949	1,625
(Acquisition) disposition of other assets	17	540	(2,562)
Net cash used in investing activities	(105,691)	(72,736)	(132,099)
Cash Flows From Financing Activities:			
Borrowings under line of credit	57,200	36,700	65,200
Payments under line of credit	(79,200)	(36,200)	(95,300)
Net payments on notes payable and other long-term debt	(1,000)	(1,161)	(1,105)

Proceeds from exercise of stock options	609	413	452
Proceeds from sale of common stock	--	--	42,140
Book overdrafts (Note 1)	(4,978)	2,543	(899)
Acquisition of treasury stock	(296)	--	--
Net cash provided by (used in) financing activities	(27,665)	2,295	10,488
Net Increase (Decrease) in Cash and Cash Equivalents	(335)	106	101
Cash and Cash Equivalents, Beginning of Year	726	391	497
Cash and Cash Equivalents, End of Year	$ 391	$ 497	$ 598
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Interest	$ 2,807	$ 1,053	$ 660
Income taxes	$ 7,779	$ (4,585)	$ (3,495)

See Note 2 for non-cash investing activities.

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

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its directly and indirectly wholly owned subsidiaries ("Unit"). The investment in limited partnerships is accounted for on the proportionate consolidation method, whereby Unit's share of the partnerships' assets, liabilities, revenues and expenses is included in the appropriate classification in the accompanying consolidated financial statements.

Nature of Business. Unit is engaged in the land contract drilling of natural gas and oil wells and the exploration, development, acquisition and production of oil and natural gas properties. Unit's current contract drilling operations are focused primarily in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast and the Rocky Mountain regions. Unit's primary exploration and production operations are also conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of its contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas. At December 31, 2003, Unit had an interest in a total of 3,393 wells and served as operator of 753 of those wells. Unit provides land contract drilling services for a wide range of customers using the drilling rigs, which it owns and operates. In 2003, 84 of Unit's 88 rigs performed contract drilling services.

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

Cash Equivalents and Book Overdrafts. Unit includes as cash equivalents, certificates of deposits and all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued prior to the end of the period, but not presented to Unit's bank for payment prior to the end of the period. At December 31, 2002 and 2003, book overdrafts of $3.6 million and $2.7 million have been included in accounts payable.

Property and Equipment. Drilling equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the units-of-production method based on estimated useful lives, including a minimum provision of 20% of the active rate when the equipment is idle. Unit uses the composite method of depreciation for drill pipe and collars and calculates the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

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

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

Goodwill. Goodwill represents the excess of the cost of the acquisition of Hickman Drilling Company, CREC Rig Equipment Company, CDC Drilling Company and SerDrilco Incorporated over the fair value of the net assets acquired. Prior to January 1, 2002 goodwill was amortized on the straight-line method using a 25 year life. Unit expensed $243,000 annually for the amortization of goodwill. On July 20, 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("FAS 142"). For goodwill and intangible assets recorded in the financial statements, FAS 142 ends the amortization of goodwill and certain intangible assets and subsequently requires, at least annually, that an impairment test be performed on such assets to determine whether the fair value has decreased. FAS 142 became effective for the fiscal years starting after December 15, 2001 (January 1, 2002 for Unit). Goodwill is all related to the drilling segment. The 2002 increase in the carrying amount of goodwill of $7,706,000 came from the goodwill acquired in the acquisition of CREC Rig Equipment Company and CDC Drilling Company and the 2003 increase in the carrying amount of goodwill of $10,928,000 came from the goodwill acquired in the acquisition of SerDrilco Incorporated. Both acquisitions are more fully discussed in Note 2. Goodwill of $7,009,000 is expected to be deductible for tax purposes. The following table shows the adjusted net income and earnings per share resulting from the removal of the amortization expense (net of income tax) recognized in the prior periods:

	2001	2002	2003
	(In thousands except per		

		share amounts)	
Adjusted Net Income:			
Reported net income	$ 62,766	$ 18,244	$ 50,189
Add back: goodwill amortized - net of income tax	88	--	--
Adjusted net income	$ 62,854	$ 18,244	$ 50,189
Basic Earnings per Share:			
Reported net income	$ 1.75	$ 0.47	$ 1.15
Add back: goodwill amortized - net of income tax	--	--	--
Adjusted net income	$ 1.75	$ 0.47	$ 1.15
Diluted Earnings per Share:			
Reported net income	$ 1.73	$ 0.47	$ 1.15
Add back: goodwill amortized - net of income tax	--	--	--
Adjusted net income	$ 1.73	$ 0.47	$ 1.15

Oil and Natural Gas Operations. Unit accounts for its oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the Securities and Exchange Commission ("SEC"). Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. Unit capitalizes internal costs that can be directly identified with its acquisition, exploration and development activities. Independent petroleum engineers annually review Unit's determination of its oil and natural gas reserves. The average composite rates used for depreciation, depletion and amortization ("DD&A") were $0.91, $1.04 and $1.14 per Mcfe in 2001, 2002 and 2003, 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 $17.5 million are excluded from the DD&A calculation. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. The full cost ceiling is based principally on the estimated future discounted net cash flows from Unit's oil and natural gas properties. As discussed in Note 13, such estimates are imprecise.

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

Unit's contract drilling subsidiary provides drilling services for its exploration and production subsidiary. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. During 2003, the contract drilling subsidiary drilled 43 wells for our exploration and production subsidiary. As required by the Securities and Exchange Commission, the profit received by our contract drilling segment of $2,259,000, $841,000 and $1,883,000 during 2001, 2002 and 2003, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our profits in current operations.

Limited Partnerships. Unit's wholly owned subsidiary, Unit Petroleum Company, is a general partner in 10 oil and natural gas limited partnerships sold privately and publicly. Some of Unit's officers, directors and employees own the interests in most of these partnerships. Unit shares partnership revenues and costs in accordance with formulas prescribed in each limited partnership agreement. The partnerships also reimburse Unit for certain administrative costs incurred on behalf of the partnerships.

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

Natural Gas Balancing. Unit uses the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Unit estimates its December 31, 2003 balancing position to be approximately 1.8 Bcf on under-produced properties and approximately 2.3 Bcf on over-produced properties. Unit has recorded a receivable of $562,000 on certain wells where we estimated that insufficient reserves are available for Unit to recover the under-production from future production volumes. Unit has also recorded a liability of $1,191,000 on certain properties where we believe there is insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Unit's policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which Unit has imbalances are not material.

Investments. Unit owns a 40% equity interest in Superior Pipeline Company LLC, a natural gas gathering and processing company. The investment, including Unit's share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets.

Unit also owns a 16.7% interest carried at cost in Eagle Energy Partnership I, L.P. ("Eagle") for $2.5 million. 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.

Employee and Director Stock Based Compensation. Unit's stock-based compensation plans, which are explained more fully in Note 6, are accounted for under the recognition and measurement principles of APB Opinion 25 "Accounting for Stock Issued to Employees," and related interpretations. Under this standard, no compensation expense is recognized for grants of options, which include an exercise price equal to or greater than the market price of the stock on the date of grant. Accordingly, based on Unit's grants in 2001, 2002 and 2003 no compensation expense has been recognized. Compensation expense included in reported net income is Unit's matching 401(k) contribution which was made in Unit common stock. The following table illustrates the effect on net income and earnings per share if Unit had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	2001	2002	2003
Net Income, as Reported (In Thousands)	$ 62,766	$ 18,244	$ 50,189
Add Stock Based Employee Compensation Expense Included in Reported Net Income - Net of Tax	671	669	858
Less Total Stock Based Employee Compensation Expense Determined Under Fair Value Based Method For All Awards	(1,615)	(1,488)	(2,114)
Pro Forma Net Income	$ 61,822	$ 17,425	$ 48,933
Basic Earnings per Share:			
As reported	$ 1.75	$ 0.47	$ 1.15
Pro forma	$ 1.72	$ 0.45	$ 1.12
Diluted Earnings per Share:			
As reported	$ 1.73	$ 0.47	$ 1.15
Pro forma	$ 1.71	$ 0.45	$ 1.12

The fair value of each option granted is estimated using the Black-Scholes model. Unit's estimate of stock volatility in 2001, 2002 and 2003 was 0.55, 0.53 and 0.52, respectively, based on previous stock performance. Dividend yield was

estimated to remain at zero with a risk free interest rate of 5.41% in 2001 and 4.24% in 2002 and 2003. Expected life ranged from 1 to 10 years based on prior experience depending on the vesting periods involved and the make up of participating employees. The aggregate fair value of options granted during 2002 and 2003 under the Stock Option Plan were $1,669,000 and $1,617,000, respectively. No options were issued under the Stock Option Plan in 2001. Under the Non-Employee Directors' Stock Option Plan the aggregate fair value of options granted during 2001 was $201,000 and $262,000 in 2002 and 2003.

Self Insurance. Unit utilizes self insurance programs for employee group health and worker's compensation. Self insurance costs are accrued based upon the aggregate of estimated liabilities for reported claims and claims incurred but not yet reported. Accrued liabilities include $3,632,000 and $7,990,000 for employer group health insurance and worker's compensation at December 31, 2002 and 2003, respectively. Unit's exposure (i.e. deductible or retention) per occurrence ranged from $200,000 for general liability to $1 million for rig physical damage. Unit has purchased stop-loss coverage

in order to limit, to the extent feasible, its per occurrence and aggregate exposure to certain claims. Following the acquisition of SerDrilco, Unit continued to use SerDrilco's ERISA governed occupational injury benefit plan to cover the SerDrilco employees in lieu of covering them under an insured Texas workers' compensation plan.

Treasury Stock. On August 30, 2001, Unit's Board of Directors authorized the purchase of up to one million shares of Unit's common stock. The timing of stock purchases are made at the discretion of management. During 2001, 30,000 shares were repurchased for $296,000. These shares were used for a portion of the company match to the 401(k) Employee Thrift Plan. No treasury stock was owned by Unit at December 31, 2002 and 2003.

Financial Instruments and Concentrations of Credit Risk. Financial instruments, which potentially subject Unit to concentrations of credit risk, consist primarily of trade receivables with a variety of national and international oil and natural gas companies. Unit does not generally require collateral related to receivables. Such credit risk is considered by management to be limited due to the large number of customers comprising Unit's customer base. During 2003, Chesapeake Operating, Inc. was our largest drilling customer and provided 15% of our total contract drilling revenues. Purchases by Cinergy Marketing & Trading LP accounted for approximately 17% of Unit's oil and natural gas revenues in 2003 while purchases by Centerpoint Energy Gas accounted for approximately 16% of Unit's oil and natural gas revenues. Unit owns a 16.7% in Eagle Energy Partners I LP, whose purchases accounted for 6% of Unit's oil and natural gas revenues in 2003. In addition, at December 31, 2002 and 2003, Unit had a concentration of cash of $3.0 million and $3.5 million, respectively, with one bank.

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

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

Unit entered into a collar contract for approximately 25% of its daily production for January and February of 2001. The collar had a floor of $26.00 and a ceiling of $33.00 and Unit received $0.86 per barrel for entering into the collar transaction. During the first quarter of 2001, the net effect of this

hedging transaction yielded an increase in oil revenues of $17,200.

During the second quarter of 2001, Unit entered into a natural gas collar contract for approximately 36% of its June and July 2001 natural gas production, at a floor price of $4.50 and a ceiling price of $5.95. During the third quarter of 2001, Unit entered into two natural gas collar contracts for approximately 38% of its September through November 2001 natural gas production. Both contracts had a floor price of $2.50. One contract had a ceiling price of $3.68 and the other contract had a ceiling price of $4.25. During 2001 natural gas collar contracts added $2,030,000 to Unit's natural gas revenues.

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

During the first quarter of 2003, Unit entered into two collar contracts covering approximately 40% of its natural gas production for the periods of April 1, 2003 through September 30, 2003. One collar had a floor of $4.00 and a ceiling of $5.75 and the other collar had a floor of $4.50 and a ceiling of $6.02. Unit also entered into two collar contracts covering approximately 25% of its oil production for the periods of May 1, 2003 through December 31, 2003. One collar had a floor of $25.00 and a ceiling of $32.20 and the other collar had a floor of $26.00 and a ceiling of $31.40. During the year 2003, the collar contracts decreased natural gas revenues by $6,000 and oil revenues by $5,000. We did not have any hedging transactions outstanding at December 31, 2003.

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

Impact of Financial Accounting Pronouncements.

On January 1, 2003 the company adopted Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-lived assets. The company owns oil and natural gas properties which require expenditures to plug and abandon the wells when the oil and natural gas reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the

period in which the liability is incurred (at the time the wells are drilled or acquired). The company does not have any assets restricted for the purpose of settling the plugging liabilities.

The following table shows the activity for the year ending December 31, 2003 relating to the company's retirement obligation for plugging liability:

	Short-Term Plugging Liability	Long-Term Plugging Liability
	(In Thousands)	
Plugging Liability 1/1/03	$ 203	$ 10,632
Accretion of Discount	8	505
Liability Incurred in the Period	--	719
Liability Settled in the Period	(65)	(120)
Liability Sold	(36)	(10)
Reclassification of Liability From Long- to Short-Term	193	(193)
Revision of Estimate	--	158
Plugging Liability 12/31/03	$ 303	$ 11,691

The effect of this change increased net property, plant and equipment by $13.0 million and liabilities, including deferred tax liabilities, by $11.7 million at January 1, 2003 and decreased net income for the year ended December 31, 2003 by $148,000 ($0.00 per share). The financial statements for the year ended December 31, 2002 have not been restated and the cumulative effect of the

change of $1.3 million net of tax ($0.03 per share) is shown as a one-time addition to income in the first quarter of 2003.

The following table shows the adjusted net income and earnings per share resulting from the accretion of the discount and change in the depreciation, depletion and amortization (both net of income tax) as if the plugging liability had been recognized in the prior year ended periods:

	2000	2001	2002
	(In thousands except per share amounts)		
Adjusted Net Income:			
Reported net income	$ 34,344	$ 62,766	$ 18,244
Add back:			
Decrease in depreciation, depletion and amortization - net of income tax	80	156	167
Deduct:			
Accretion of discount - net of income tax	(231)	(260)	(296)
Adjusted net income	$ 34,193	$ 62,662	$ 18,115
Basic Earnings per Share:			
Reported net income	$ 0.96	$ 1.75	$ 0.47
Net adjustment to income from change in accounting principle	--	(0.01)	--
Adjusted basic earnings per share	$ 0.96	$ 1.74	$ 0.47
Diluted Earnings per Share:			
Reported net income	$ 0.95	$ 1.73	$ 0.47
Net adjustment to income from change in accounting principle	--	--	(0.01)
Adjusted diluted earnings per share	$ 0.95	$ 1.73	$ 0.46

If FAS 143 had been applied at January 1, 2000 and December 31, 2000, 2001 and 2002, the plugging liability would have been $8.0 million, $8.7 million, $9.7 million and $10.8 million, respectively, assuming the liability was measured using the information, assumptions and interest rates used as of the adoption date of January 1, 2003.

On January 17, 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of ARB 51" ("FIN 46"). The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate

the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest

or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. FIN 46, as amended, was effective for Unit in the fourth quarter of 2003 as it applies to entities created after February 1, 2003. The adoption of FIN 46 with respect to these entities, did not have an impact on Unit's financial position or results of operations. For entities created prior to February 1, 2003, which are not special purpose entities, as defined in FIN 46, Unit will have to adopt FIN 46, as amended, in the quarter ending March 31, 2004. Unit is still evaluating FIN 46 with regard to these types of entities in which it has an ownership interest, primarily oil and gas partnerships and its equity investment in Superior pipeline. FIN 46 may require full consolidation of these entities which would increase total assets with an offsetting minority interest for the percentage not owned by Unit. There will be no net impact to results of operations from the adoption of FIN 46.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (FAS 142) were issued by the FASB in June 2001 and became effective for Unit on July 1, 2001 and January 1, 2002, respectively. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, FAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. FAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under FAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. Depending on how the accounting and disclosure literature is applied, oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and natural gas reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. In addition, the notes to the Unit's financial statements would include the disclosures required by FAS 141 and 142 regarding intangibles. To date, Unit, like many other oil and gas companies, has included oil and gas extraction rights as part of the oil and gas properties, even after FAS 141 and 142 became effective.

Unit's results of operations and cash flows would not be affected, since these oil and gas mineral extraction rights would continue to be amortized in accordance with full cost accounting rules.

At December 31, 2002 and 2003, Unit had undeveloped leaseholds of approximately $13.2 million and $14.8 million, respectively that would be classified on its balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $18.1 million and $24.6 million, respectively that would be classified as "intangible developed leasehold" if the interpretations were applied. This classification would require Unit to make the disclosures set forth under FAS 142 related to these interests.

Unit intends to continue to classify its oil and gas mineral extraction rights as tangible oil and gas properties until further guidance is provided.

NOTE 2 - ACQUISITIONS
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On December 8, 2003, Unit acquired SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, for $35.0 million in cash. The terms of the acquisition include an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the three years following the acquisition. The assets of SerDrilco Incorporated included 12 drilling rigs, spare drilling equipment, a fleet of 12 larger trucks and trailers, various other vehicles and a district office and equipment yard in and near Borger, Texas. The results of operations for the acquired entity are included in the statement of operations for the period beginning December 8, 2003 and continuing through December 31, 2003.

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

Allocation of Total Consideration Paid and Goodwill Recognized:	

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

On August 15, 2002, Unit completed the acquisition of CREC Rig Equipment Company and CDC Drilling Company ("Cactus Acquisition"). Both of these acquisitions were stock purchase transactions. Unit issued 6,819,748 shares of common stock and paid $3,813,053 for all the outstanding shares of CREC Rig Equipment Company and issued 400,252 shares of common stock and paid $686,947 for all the outstanding shares of CDC Drilling Company. The assets of the acquired companies included 20 drilling rigs, spare drilling equipment and vehicles. What we paid in both transactions was determined through arms-length negotiations between the parties and only the cash portion of the transaction appears in the investing and financing activities of Unit's Consolidated Statement of Cash Flows. The results of operations for the acquired entities are included in the statement of operations for the period beginning August 15, 2002 and continuing through December 31, 2003.

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

Calculation of Consideration Paid:

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

Allocation of Total Consideration Paid:

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

Unaudited summary pro forma results of operations for Unit, reflecting the Cactus Acquisition as if it had occurred at the beginning of the year ended December 31, 2001 are as follow:

	Year Ended December 31, 2001	Year Ended December 31, 2002
	(In thousands except per Per share amounts)	
Revenues	$ 311,104	$ 215,805

Net Income	$ 70,457	$ 15,320
Net Income per Common Share (Diluted)	$ 1.62	$ 0.34

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

NOTE 3 - EARNINGS PER SHARE

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

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the Year Ended December 31, 2001:			
Basic earnings per common share	$ 62,766	35,967	$ 1.75
Effect of dilutive stock options		291	
Diluted earnings per common share	$ 62,766	36,258	$ 1.73
For the Year Ended December 31, 2002:			
Basic earnings per common share	$ 18,244	38,844	$ 0.47
Effect of dilutive stock options		268	
Diluted earnings per common share	$ 18,244	39,112	$ 0.47

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount

	(In thousands except per share amounts)		
For the Year Ended December 31, 2003:			
Basic earnings per common share:			
Income before change in accounting principle	$ 48,864	43,616	$ 1.12
Cumulative effect of change in accounting principle net of income tax	1,325	43,616	0.03
Net Income	$ 50,189	43,616	$ 1.15
Diluted earnings per common share:			
Weighted average number of common shares used in basic earnings per common share		43,616	
Effect of dilutive stock options		157	
Weighted average number of common shares and dilutive potential common shares used in diluted earnings per share		43,773	
Income before change in accounting principle	$ 48,864	43,773	$ 1.12
Cumulative effect of change in accounting principle net of income tax	1,325	43,773	0.03
Net Income	$ 50,189	43,773	$ 1.15

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,:

	2001	2002	2003
Options	153,000	198,500	137,850
Average Exercise Price	$ 16.79	$ 19.01	$ 22.52

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

Long-term debt consisted of the following as of December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Revolving Credit and Term Loan, with Interest at December 31, 2002 and 2003 of 2.5% and 4.0%, Respectively	$ 30,500	$ 400
Notes Payable for Hickman Drilling Company Acquisition with Interest at December 31, 2002 of 4.25%	1,000	--

	31,500	400
Less Current Portion	1,000	--
Total Long-Term Debt	$ 30,500	$ 400

At December 31, 2003, Unit had a $100 million bank loan agreement consisting of a revolving credit facility through May 1, 2005 and a term loan thereafter, maturing on May 1, 2008. On January 30, 2004, in conjunction with Unit's acquisition of PetroCorp Incorporated, Unit replaced its loan agreement with a revolving credit facility totaling $150 million having a four year term ending January 30, 2008. Borrowings under the new credit facility are limited to a commitment amount. Although, the current value of Unit's assets under the latest loan value computation supported a full $150 million, Unit elected to set the loan commitment at

$120 million in order to reduce financing costs. Unit pays a commitment fee of ..375 of 1% for any unused portion of the commitment amount. Unit paid origination, agency and syndication fees of $515,000 at the inception of the new agreement $40,000 of which will be paid annually and the remainder of the fees will be amortized over the 4 year life of the loan.

The borrowing base under the current credit facility is subject to a semi-annual re-determination on May 10 and November 10 of each year, beginning May 10, 2004. The calculation 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. In addition, an amount representing a part of the value of Unit's drilling rig fleet, limited to $20 million, is added to the borrowing base. Provisions are also in the agreement which allow for one requested special re-determination of the borrowing base by either the lender or Unit between each scheduled re-determination date if conditions warrant such a request.

At Unit's election, any portion of the debt outstanding may be fixed at a Eurodollar Rate for 30, 60, 90 or 180 day terms. During any Eurodollar Rate funding period the outstanding principal balance of the note to which such Eurodollar Rate option applies may be repaid upon three days prior notice to the Administrative Agent. Interest on the Eurodollar Rate is computed at the Eurodollar Base Rate applicable for the interest period plus 1.00% tp 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 Eurodollar Rate bear interest at the JPMorgan Chase Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty.

The loan agreement includes prohibitions against:

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

The loan agreement also requires that at the end of each quarter:

- consolidated net worth of at least $350 million,
- a current ratio (as defined in the loan agreement) of not less than 1 to 1 and
- a leverage ratio of long-term debt to consolidated EBITDA (as defined in the loan agreement) for the most recently ended rolling four fiscal quarters of no greater than 3.25 to 1.0.

Other long-term liabilities consisted of the following as of December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Separation Benefit Plan	$ 2,081	$ 2,545

Deferred Compensation Plan	1,391	1,829
Retirement Agreement	1,412	1,349
Gas Balancing Liability	1,020	1,191
Plugging Liability	--	11,994
	5,904	18,908
Less Current Portion	465	1,015
Total Other Long-Term Liabilities	$ 5,439	$ 17,893

Estimated annual principal payments under the terms of long-term debt and other long-term liabilities from 2004 through 2008 are $1,015,000, $606,000, $686,000, $841,000 and $679,000. Based on the borrowing rates currently available to Unit for debt with similar terms and maturities, long-term debt at December 31, 2003 approximates its fair value.

NOTE 5 - INCOME TAXES
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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:

	2001	2002	2003
		(In thousands)	
Income Tax Expense Computed by Applying the Statutory Rate	$ 34,538	$ 9,739	$ 27,213
State Income Tax, Net of Federal Benefit	2,859	834	2,333
Statutory Depletion and Other	(1,484)	(1,021)	(659)
Income tax expense	$ 35,913	$ 9,552	$ 28,887

Deferred tax assets and liabilities are comprised of the following at December 31, 2002 and 2003:

	2002	2003
	(In thousands)	
Deferred Tax Assets:		
Allowance for losses and nondeductible accruals	$ 3,942	$ 9,972
Net operating loss carryforward	17,752	20,745
Statutory depletion carryforward	4,231	4,476
Alternative minimum tax credit carryforward	395	395
Gross deferred tax assets	26,320	35,588
Deferred Tax Liability:		
Depreciation, depletion and amortization	(110,598)	(159,990)
Net deferred tax liability	(84,278)	(124,402)
Current Deferred Tax Asset	2,042	2,651
Non-Current - Deferred Tax Liability	$ (86,320)	$ (127,053)

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

At December 31, 2003, Unit has an excess statutory depletion carryforward of approximately $11,778,000, which may be carried forward indefinitely and is available to reduce future taxable income, subject to statutory limitations. At December 31, 2003, Unit has net operating loss carryforwards of approximately $54,591,000 which expire from 2019 to 2022.

NOTE 6 - EMPLOYEE BENEFIT AND COMPENSATION PLANS
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In December 1984, the Board of Directors approved the adoption of an Employee Stock Bonus Plan ("the Plan") whereby 330,950 shares of common stock were authorized for issuance under the Plan. On May 3, 1995, Unit's shareholders approved and amended the Plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the Plan. Under the terms of the Plan, bonuses may be granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in annual installments subject to certain restrictions. No shares were issued under the Plan in 2001, 2002 and 2003.

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

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2001	719,700	$ 6.87
Exercised	(177,200)	3.13
Cancelled	(10,400)	10.26
Outstanding at December 31, 2001	532,100	8.09
Granted	160,000	19.03
Exercised	(59,400)	5.67
Outstanding at December 31, 2002	632,700	11.08
Granted	116,850	22.89
Exercised	(202,900)	5.94
Cancelled	(9,900)	15.41
Outstanding at December 31, 2003	536,750	$ 15.52

	Outstanding Options at December 31, 2003		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price

$ 3.00 - $ 4.00	99,600	3.8 years	$ 3.52
$ 7.25 - $10.00	45,700	3.2 years	$ 8.52
$11.31 - $14.06	3,500	5.8 years	$ 13.28
$16.69 - $22.95	387,950	8.6 years	$ 19.44

	Exercisable Options At December 31, 2003	
Exercise Prices	Number of Shares	Weighted Average Exercise Price
$ 2.75 - $ 4.00	99,600	$ 3.52
$ 7.25 - $10.00	45,700	$ 8.52
$11.31 - $14.06	2,500	$ 12.96
$16.69 - $19.04	108,500	$ 17.49

Options for 329,300, 355,100 and 256,300 shares were exercisable with weighted average exercise prices of $6.25, $7.28 and $5.32 at December 31, 2001, 2002 and 2003, respectively.

In February and May 1992, the Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors' Stock Option Plan (the "Old Plan") and in February and May 2000, the Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (the "Directors' Plan"). Under the Directors' Plan, which replaced the Old Plan, an aggregate of 300,000 shares of Unit's common stock may be issued upon exercise of the stock options. Under the Old Plan, on the first business day following each annual meeting of stockholders of Unit, each person who was then a member of the Board of Directors of Unit and who was not then an employee of Unit or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. Under the Directors' Plan, commencing with the year 2000 annual meeting, the amount granted has been increased to 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. No stock options may be exercised during the first six months of its term except in case of death and no stock options are exercisable after 10 years from the date of grant.

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2001	95,000	$ 7.03
Granted	17,500	17.54
Exercised	(37,000)	6.80
Outstanding at December 31, 2001	75,500	9.58
Granted	21,000	20.10
Exercised	(2,500)	1.75
Outstanding at December 31, 2002	94,000	12.14
Granted	21,000	20.46

Exercised	(34,500)	7.73
Outstanding at December 31, 2003	80,500	$ 8.94

Exercise Prices	Outstanding and Exercisable Options at December 31, 2003		
	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$ 2.88 - $ 3.75	2,500	0.4 years	$ 2.88
$ 6.87 - $ 9.00	15,000	3.8 years	$ 7.58
$12.19 - $17.54	21,000	7.0 years	$ 15.76
$20.10 - $20.46	42,000	8.8 years	$ 20.28

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 35,016, 87,452 and 61,175 shares of common stock and recognized expense of $1,082,000, $1,079,000 and $1,365,000 in 2001, 2002 and 2003, 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, 2001, 2002 and 2003 totaled $1,277,000, $1,391,000 and $1,829,000, respectively. Unit recognizes payroll expense and records a liability at the time of deferral.

Effective January 1, 1997, Unit adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with Unit is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to 4 weeks salary for every whole year of service completed with Unit up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against Unit in exchange for receiving the separation benefits. On October 28, 1997, Unit adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Unit recognized expense of $589,000, $619,000 and $707,000 in 2001, 2002 and 2003, respectively, for benefits associated with anticipated payments from both separation plans.

Unit has entered into key employee change of control contracts with six 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
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Unit Petroleum Company serves as the general partner of 10 oil and gas limited partnerships. Four were formed for investment by third parties and six (the employee partnerships) were formed to allow employees of Unit and its subsidiaries and directors of Unit to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984, 1985 and 1986. An additional third party partnership, the 1979 Oil and Gas Limited Partnership was dissolved on July 1, 2003. Employee partnerships have been formed for each year beginning with 1984. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount ($22,680 for 2002 and 2003 and $36,000 for 2004) 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:

	2001	2002	2003
	(In thousands)		
Contract Drilling	$ 416	$ 209	$ 428
Well Supervision and Other Fees	$ 498	$ 510	$ 236
General and Administrative Expense Reimbursement	$ 193	$ 210	$ 209

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

A subsidiary of Unit paid the Partnerships, for which Unit or a subsidiary is the general partner, $3,000, $1,000 and $2,000 during the years ended December 31, 2001, 2002 and 2003, respectively, for purchases of natural gas production.

Unit owns a 40% equity interest in Superior Pipeline Company LLC, an

Oklahoma Limited Liability Company. Superior is a natural gas gathering and processing company. The investment, including Unit's share of the equity in the earnings of this company, totaled $3.0 million at December 31, 2003 and is reported in other assets in Unit's consolidated balance sheet. During 2003, Superior Pipeline Company LLC purchased $3.3 million of our natural gas production and paid $64,000 for our natural gas liquids. We paid this company $39,000 for gathering and compression services.

Unit also owns a 16.7% limited partnership interest in Eagle Energy Partnership I, L.P. ("Eagle"), carried at cost, for $2.5 million. 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. Total purchases by Eagle Energy Partnership I, L.P., which are competitively marketed, accounted for 6% of Unit's oil and natural gas revenues in 2003. Unit increased its sales to Eagle Energy Partners I LP since it first starting selling natural gas to them in August, 2003. For the period August through December 2003 Eagle has purchased 16% of Unit's oil and natural gas revenues.

NOTE 8 - SHAREHOLDER RIGHTS PLAN
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Unit maintains a Shareholder Rights Plan (the "Plan") designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of Unit without offering fair value to all shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

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

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

NOTE 9 - COMMITMENTS AND CONTINGENCIES
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Unit leases office space in Tulsa and Woodward Oklahoma and Houston Texas under the terms of operating leases expiring through January 31, 2010. Future minimum rental payments under the terms of the leases are approximately $719,000, $710,000, $714,000, $531,000 and $423,000 in 2004, 2005, 2006, 2007 and 2008, respectively. Total rent expense incurred by the Company was $582,000, $678,000 and $752,000 in 2001, 2002 and 2003, 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 $1,000 and $106,000 in 2002 and 2003, respectively, for such limited partners' interests. No repurchases were made in 2001. In 2001, Unit paid $15,000 for interests in two of the Questa limited partnerships and subsequently dissolved one of the Questa partnerships.

Unit manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews

evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to Unit's satisfaction, or agree to assume liability for the remediation of the property.

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

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

NOTE 10 - INDUSTRY SEGMENT INFORMATION
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Unit has two business segments: Contract Drilling and Oil and Natural Gas, representing its two main business units offering different products and services. The Contract Drilling segment provides land contract drilling of oil and natural gas wells and the Oil and Natural Gas segment is engaged in the development, acquisition and production of oil and natural gas properties.

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

	2001	2002	2003
		(In thousands)	
Revenues:			
Contract drilling	$ 169,301	$ 119,014	$ 188,832
Elimination of intersegment revenue	2,259	841	5,686
Contract drilling net of intersegment revenue	167,042	118,173	183,146
Oil and natural gas	90,237	67,959	116,609
Other	1,900	1,504	2,829
Total revenues	$ 259,179	$ 187,636	$ 302,584
Operating Income (1):			
Contract drilling	$ 62,148	$ 12,151	$ 20,740
Oil and natural gas	45,925	23,826	64,097
Total operating income	108,073	35,977	84,837
General and administrative expense	(8,476)	(8,712)	(9,222)
Interest expense	(2,818)	(973)	(693)
Other income (expense)- net	1,900	1,504	2,829
Income before income taxes	$ 98,679	$ 27,796	$ 77,751
Identifiable Assets (2):			
Contract drilling	$ 183,471	$ 299,655	$ 364,855
Oil and natural gas	220,476	261,440	327,172
Total identifiable assets	403,947	561,095	692,027
Corporate assets	13,306	17,068	20,898
Total assets	$ 417,253	$ 578,163	$ 712,925

	2001	2002	2003
		(In thousands)	
Capital Expenditures:			
Contract drilling	$ 51,280	$ 139,298 (3)	$ 71,899 (4)
Oil and natural gas	56,933	58,778	80,883 (5)
Other	539	516	3,940
Total capital expenditures	$ 108,752	$ 198,592	$ 156,722
Depreciation, Depletion, Amortization and Impairment:			
Contract drilling	$ 13,888	$ 14,684	$ 23,644
Oil and natural gas	22,116	23,338	27,343
Other	638	635	796
Total depreciation, depletion, amortization and impairment	$ 36,642	$ 38,657	$ 51,783

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

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

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

(4) Includes $10.9 million for goodwill.

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

NOTE 11 - SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2002 and 2003 is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Year Ended December 31, 2002:				
Revenues	$ 38,730	$ 44,753	$ 48,272	$ 55,881
Gross profit(1)	$ 6,515	$ 10,295	$ 8,107	$ 11,060
Income before income taxes	$ 4,254	$ 8,297	$ 6,022	$ 9,223
Net income(2)	$ 2,642	$ 5,108	$ 3,708	$ 6,786
Earnings per common share:				
Basic (3)	$ 0.07	$ 0.14	$ 0.09	$ 0.16
Diluted (4)	$ 0.07	$ 0.14	$ 0.09	$ 0.16
Year Ended December 31, 2003:				
Revenues	$ 68,446	$ 72,980	$ 78,201	$ 82,957
Gross profit(1)	$ 22,447	$ 20,214	$ 22,251	$ 19,925
Income before income taxes and change in accounting principle	$ 20,418	$ 18,857	$ 20,598	$ 17,878
Income before change in accounting principle	$ 12,659	$ 11,691	$ 12,763	$ 11,751
Net Income(2)	$ 13,984	$ 11,691	$ 12,763	$ 11,751

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
Earnings Before Change in				

Accounting Principle per Common Share:				
Basic	$ 0.29	$ 0.27	$ 0.29	$ 0.27
Diluted	$ 0.29	$ 0.27	$ 0.29	$ 0.27
Net Income per Common Share:				
Basic	$ 0.32	$ 0.27	$ 0.29	$ 0.27
Diluted	$ 0.32	$ 0.27	$ 0.29	$ 0.27

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

(2) The net income for the three months ended December 31, 2002 and 2003 includes a tax benefit of $1.1 million and $0.8 million, respectively, relating primarily to an increase in the estimated amount of statutory depletion carryforward.

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

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

NOTE 12 - SUBSEQUENT EVENT
- --------------------------

On January 30, 2004 Unit acquired the outstanding common stock of PetroCorp Incorporated for $182.1 million in cash. PetroCorp Incorporated explored and developed oil and natural gas properties primarily in Texas and Oklahoma. Approximately 84% of the oil and natural gas properties acquired in the acquisition are located in the Mid-Continent and Permian basins, while 6% are located in the Rocky Mountains and 10% are located in the Gulf Coast basin. The acquired properties increased Unit's reserve base by approximately 56.7 billion equivalent cubic feet of natural gas and provide additional locations for development drilling in the future. With the acquisition of PetroCorp Incorporated, Unit also entered into a new $150 million credit facility to replace its existing loan agreement as more fully discussed in Note 4.

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

Working Capital	$ 93,668
Undeveloped Oil and Natural Gas Properties	6,557
Proved Oil and Natural Gas Properties	114,518
Property and Equipment - Other	401
Other Assets	1,499
Other Long-Term Liabilities	(5,557)
Deferred Income Taxes (net)	(28,966)
Total consideration	$ 182,120

Unaudited summary pro forma results of operations for Unit, reflecting the above described acquisition as if it had occurred at the beginning of the year ended December 31, 2002 and December 31, 2003, are as follows, respectively; revenues, $217.0 million and $339.6 million; income from continuing operations of $19.5 million and $55.2 million; net income of $19.5 million and $53.5 million; income from continuing operations per common share (diluted) of $0.50

and $1.26 and net income per common shares (diluted) of $0.50 and $1.22. The pro forma results of operations are not necessarily indicative of the actual results of operations that would have occurred had the purchase actually been made at the beginning of the respective period nor of the results which may occur in the future.

NOTE 13 - OIL AND NATURAL GAS INFORMATION
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The capitalized costs at year end and costs incurred during the year were as follows:

	USA	Canada	Total
	(In thousands)		
2001:			
Capitalized costs:			
Proved properties	$ 391,216	$ 888	$ 392,104
Unproved properties	14,207	180	14,387
	405,423	1,068	406,491
Accumulated depreciation, depletion, amortization and impairment	(196,270)	(475)	(196,745)
Net capitalized costs	$ 209,153	$ 593	$ 209,746
Cost incurred:			
Unproved properties acquired	$ 7,503	$ 21	$ 7,524
Proved properties acquired	1,419	--	1,419
Exploration	9,336	--	9,336
Development	38,359	295	38,654
Total costs incurred	$ 56,617	$ 316	$ 56,933
2002:			
Capitalized costs:			
Proved properties	$ 448,331	$ 895	$ 449,226
Unproved properties	15,692	332	16,024
	464,023	1,227	465,250
Accumulated depreciation, depletion, amortization and impairment	(218,956)	(520)	(219,476)
Net capitalized costs	$ 245,067	$ 707	$ 245,774
Cost incurred:			
Unproved properties acquired	$ 5,330	$ 152	$ 5,482
Proved properties acquired	13,379	--	13,379
Exploration	6,591	--	6,591
Development	33,319	7	33,326
Total costs incurred	$ 58,619	$ 159	$ 58,778

	USA	Canada	Total
	(In thousands)		
2003:			
Capitalized costs:			
Proved properties	$ 527,196	$ 914	$ 528,110
Unproved properties	17,149	337	17,486

	544,345	1,251	545,596
Accumulated depreciation, depletion, amortization and impairment	(240,047)	(540)	(240,587)
Net capitalized costs	$ 304,298	$ 711	$ 305,009
Cost incurred:			
Unproved properties acquired	$ 8,611	$ 19	$ 8,630
Proved properties acquired	2,557	--	2,557
Exploration	7,071	--	7,071
Development(1)	62,620	5	62,625
Total costs incurred	$ 80,859	$ 24	$ 80,883

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

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2003, by the year in which such costs were incurred.

	2000 and Prior	2001	2002	2003	Total
	(In thousands)				
Undeveloped Leasehold Acquired	$ 3,341	$ 3,272	$ 3,187	$ 7,686	$ 17,486

The results of operations for producing activities are provided below.

	USA	Canada	Total
	(In thousands)		
2001:			
Revenues	$ 86,810	$ 190	$ 87,000
Production costs	(18,636)	(23)	(18,659)
Depreciation, depletion and amortization	(19,756)	(40)	(19,796)
	48,418	127	48,545
Income tax expense	(17,621)	(40)	(17,661)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 30,797	$ 87	$ 30,884
2002:			
Revenues	$ 64,534	$ 87	$ 64,621
Production costs	(17,300)	(25)	(17,325)
Depreciation, depletion and amortization	(22,685)	(45)	(22,730)
	24,549	17	24,566
Income tax expense	(8,436)	(5)	(8,441)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 16,113	$ 12	$ 16,125

2003:			
Revenues	$ 114,398	$ 171	$ 114,569
Production costs	(21,366)	(21)	(21,387)
Depreciation, depletion and amortization	(27,059)	(20)	(27,079)
	65,973	130	66,103
Income tax expense	(24,508)	(41)	(24,549)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 41,465	$ 89	$ 41,554

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)					
2001:						
Proved developed and undeveloped reserves:						
Beginning of year	4,183	215,196	--	441	4,183	215,637
Revision of previous estimates	(214)	(24,253)	--	(7)	(214)	(24,260)
Extensions, discoveries and other additions	861	54,521	--	--	861	54,521
Purchases of minerals in place	8	1,246	--	--	8	1,246
Sales of minerals in place	(3)	(26)	--	--	(3)	(26)
Production	(492)	(18,819)	--	(45)	(492)	(18,864)
End of Year	4,343	227,865	--	389	4,343	228,254
Proved developed reserves:						
Beginning of year	3,222	162,718	--	389	3,222	163,107
End of year	2,753	150,419	--	338	2,753	150,757
2002:						
Proved developed and undeveloped reserves:						
Beginning of year	4,343	227,865	--	389	4,343	228,254
Revision of previous estimates	(166)	(10,543)	--	(31)	(166)	(10,574)
Extensions, discoveries and other additions	230	29,541	--	--	230	29,541
Purchases of minerals in place	192	16,558	--	--	192	16,558
Sales of minerals in place	(30)	--	--	--	(30)	--
Production	(473)	(18,927)	--	(41)	(473)	(18,968)
End of Year	4,096	244,494	--	317	4,096	244,811
Proved developed reserves:						
Beginning of year	2,753	150,419	--	338	2,753	150,757
End of year	2,951	168,049	--	317	2,951	168,366

	USA		Canada		Total	
	Oil Bbls(1)	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf	Oil Bbls	Natural Gas Mcf
			(In thousands)			
2003:						
Proved developed and undeveloped reserves:						
Beginning of year	4,096	244,494	--	317	4,096	244,811
Revision of previous estimates	629	(10,510)	--	371	629	(10,139)
Extensions, discoveries and other additions	1,000	39,762	--	--	1,000	39,762
Purchases of minerals in place	8	437	--	--	8	437
Sales of minerals in place	(76)	(31)	--	--	(76)	(31)
Production	(516)	(20,610)	--	(38)	(516)	(20,648)
End of Year	5,141	253,542	--	650	5,141	254,192
Proved developed reserves:						
Beginning of year	2,951	168,049	--	317	2,951	168,366
End of year	3,984	182,203	--	650	3,984	128,853

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(1) Oil includes natural gas liquids in barrels.

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

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

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

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

Reserves which can be produced economically through application of improved

recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following:

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

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

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

Estimates of oil and natural gas reserves require extensive judgments of reservoir engineering data as previously explained. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth herein is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves nor of estimated future cash flows.

The standardized measure of discounted future net cash flows ("SMOG") was calculated using year-end prices and costs, and year-end statutory tax rates, adjusted for permanent differences, that relate to existing proved oil and natural gas reserves. SMOG as of December 31 is as follows (unaudited):

	USA	Canada	Total
	(In thousands)		
2001:			
Future cash flows	$ 676,051	$ 975	$ 677,026

Future production costs	(220,590)	(311)	(220,901)
Future development costs	(58,909)	(30)	(58,939)
Future income tax expenses	(94,037)	(134)	(94,171)
Future net cash flows	302,515	500	303,015
10% annual discount for estimated timing of cash flows	(125,238)	(194)	(125,432)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 177,277	$ 306	$ 177,583
2002:			
Future cash flows	$1,256,434	$ 1,400	$1,257,834
Future production costs	(320,940)	(309)	(321,249)
Future development costs	(65,266)	--	(65,266)
Future income tax expenses	(250,413)	(233)	(250,646)
Future net cash flows	619,815	858	620,673
10% annual discount for estimated timing of cash flows	(275,015)	(344)	(275,359)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 344,800	$ 514	$ 345,314
2003:			
Future cash flows	$1,548,785	$ 3,500	$1,552,285
Future production costs	(418,007)	(581)	(418,588)
Future development costs	(72,891)	--	(72,891)
Future income tax expenses	(313,827)	(805)	(314,632)
Future net cash flows	744,060	2,114	746,174
10% annual discount for estimated timing of cash flows	(325,182)	(738)	(325,920)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 418,878	$ 1,376	$ 420,254

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

	USA	Canada	Total
	(In thousands)		
2001:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (68,174)	$ (167)	$ (68,341)
Net changes in prices and production costs	(768,295)	(1,600)	(769,895)
Revisions in quantity estimates and changes in production timing	(32,705)	13	(32,692)
Extensions, discoveries and improved recovery, less related costs	54,127	--	54,127
Changes in estimated future development cost	2,673	--	2,673
Previously estimated cost incurred during the period	7,361	--	7,361
Purchases of minerals in place	1,217	--	1,217
Sales of minerals in place	(220)	--	(220)
Accretion of discount	99,953	205	100,158
Net change in income taxes	271,421	524	271,945
Other - net	(64,668)	(108)	(64,776)
Net change	(497,310)	(1,133)	(498,443)

Beginning of year	674,587	1,439	676,026
End of year	$ 177,277	$ 306	$ 177,583
2002:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (47,230)	$ (62)	$ (47,292)
Net changes in prices and production costs	230,934	363	231,297
Revisions in quantity estimates and changes in production timing	(49,000)	(110)	(49,110)
Extensions, discoveries and improved recovery, less related costs	60,957	--	60,957
Changes in estimated future development cost	1,743	--	1,743
Previously estimated cost incurred during the period	9,911	30	9,941
Purchases of minerals in place	23,334	--	23,334
Sales of minerals in place	(150)	--	(150)
Accretion of discount	23,080	39	23,119
Net change in income taxes	(84,843)	(59)	(84,902)
Other - net	(1,213)	7	(1,206)
Net change	167,523	208	167,731
Beginning of year	177,277	306	177,583
End of year	$ 344,800	$ 514	$ 345,314

	USA	Canada	Total
	(In thousands)		
2003:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (93,948)	$ (150)	$ (94,098)
Net changes in prices and production costs	65,611	195	65,806
Revisions in quantity estimates and changes in production timing	(14,637)	1,007	(13,630)
Extensions, discoveries and improved recovery, less related costs	113,421	--	113,421
Changes in estimated future development cost	(5,356)	--	(5,356)
Previously estimated cost incurred during the period	15,664	--	15,664
Purchases of minerals in place	881	--	881
Sales of minerals in place	(837)	--	(837)
Accretion of discount	48,317	66	48,383
Net change in income taxes	(38,950)	(386)	(39,336)
Other - net	(16,088)	130	(15,958)
Net change	74,078	862	74,940
Beginning of year	344,800	514	345,314
End of year	$ 418,878	$ 1,376	$ 420,254

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 $32.52 and natural gas $5.67 relating to proved reserves to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

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

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

REPORT OF INDEPENDENT AUDITORS

The Shareholders and Board of Directors
Unit Corporation

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, 2002 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, 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 therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an

opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with auditing standards generally accepted in the United States of America which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 18, 2004

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

None.

Item 9a. Controls and Procedures.

(a) Evaluation of Disclosure Controls and Procedures

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

(b) 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.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information regarding Directors and Executive Officers appearing under the headings "Item 1: Election of Directors", and "Other Matters" of our 2004 Proxy Statement is incorporated by reference in this section. The information under the heading "Executive Officers" in Items 1 and 2 of this Form 10-K is also incorporated by reference in this section.

Item 11. Executive Compensation

The information appearing under the headings "Directors' Compensation and Benefits", "Executive Compensation", "Termination of Employment & Change in Control Arrangements", "Compensation Committee Interlocks and Insider Participation" and "Report of the Compensation Committee" of our 2004 Proxy Statement is incorporated by reference.

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

The information appearing under the heasding "Ownership of Our Common Stock by Beneficial Owners and Management" of our 2004 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions

The information appearing under the heading "Other Matters" of our 2004 Proxy Statement is incorporated by reference.

ITEM 14. Principal Accounting Fees and Services.

The information appearing under the headings "Report of Audit Committee", "Principal Accounting Fees and Services" and "Ratification of Appointment of Auditors" of our 2004 Proxy Statement is incorporated by reference.

PART IV

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

(a) Financial Statements, Schedules and Exhibits:

1. Financial Statements:

Included in Part II of this report:
- Consolidated Balance Sheets as of December 31, 2002 and 2003
- Consolidated Statements of Income for the years ended December 31, 2001, 2002 and 2003
- Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2001, 2002 and 2003
- Consolidated Statements of Cash Flows for the years ended December 31, 2001, 2002 and 2003
- Notes to Consolidated Financial Statements
- Report of Independent Auditors

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 2001, 2002 and 2003:

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

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

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

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

4.2.8 Second Amendment of the Rights Agreement, dated August 14, 2002, between the Company and Mellon Shareholder Services LLC, as Rights Agent (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2002, which is incorporated herein by reference).

4.3 Indenture (filed as Exhibit 4.3 to Unit's Form S-3 filed with the S.E.C. File No. 333-104165, which is incorporated herein by reference).

10.1.26 Loan Agreement dated January 30, 2004 (filed herein).

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

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

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

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

herein by reference).

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

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

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

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

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

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

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

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

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

10.2.38 Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).

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

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

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

21 Subsidiaries of the Registrant (filed herein).

23.1 Consent of Independent Accountants (filed herein).

23.2 Consent of Independent Petroleum Engineers (filed herein).

31.1 Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).

31.2 Certification of Chief Financial Officer under Rule 13a -14(a) of the Exchange Act (filed herein).

32.1 Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein).

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

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

(b) Reports on Form 8-K:

On October 22, 2003, we filed a report on Form 8-K under items 7 and 12. This report announced our results of operations and financial condition for the quarter ended September 30, 2003. The press release regarding this announcement was furnished as an exhibit.

On October 27, 2003, we filed a report on Form 8-K under items 5 and 7. This report announced that our Board of Directors has elected Mr. Mark E. Monroe to the Company's Board of Directors. The press release regarding this announcement was furnished as an exhibit.

On November 21, 2003, we filed a report on Form 8-K under items 5 and 7. This report announced that we signed an agreement to acquire Serdrilco Incorporated and its subsidiary, Service Drilling Southwest LLC, a U.S. land drilling company located in Borger, Texas, for $35.0 million in cash and an earn-out provision allowing the sellers to obtain one-half of the cash flow in excess of $10 million for each of the next three years. The press release regarding this announcement was furnished as an exhibit.

On December 8, 2003, we filed a report on Form 8-K under items 7 and 9. This report announced the completion of the acquisition of SerDrilco Incorporated and its subsidiary, Service Drilling Southwest LLC. We also announced we intend to offer 2 million shares of our common stock pursuant to an effective shelf registration statement filed with the Securities and Exchange Commission. The press releases regarding both of the announcements were furnished as exhibits.

On December 9, 2003, we filed a report on Form 8-K/A under item 7. This report updated the proforma financial statements related to the acquisition of CREC Rig Acquisition Company LLC and CDC Drilling Company.

On December 10, 2003, we filed a report on Form 8-K under items 7 and 9. This report announced that the previously announced public offering of 2 million shares of our common stock was priced at $22.00 per share and we anticipate the transaction will close on December 15, 2003. The press release regarding this announcement was furnished as an exhibit.

On December 11, 2003, we filed a report on Form 8-K under items 5 and 7. This report filed exhibits in connection with a prospectus supplement relating to the issuance and sale in an underwritten public offering of 2,000,000 shares of the Company's common stock.

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, 2001	$ 919	$ --	$ 315	$ 604
Year ended December 31, 2002	$ 604	$ 603	$ 4	$ 1,203
Year ended December 31, 2003	$ 1,203	$ 645	$ 625	$ 1,223

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 10, 2004 By: /s/ John G. Nikkel

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 10th day of March, 2004.

Name	Title
/s/ John G. Nikkel JOHN G. NIKKEL	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)
/s/ Larry D. Pinkston LARRY D. PINKSTON	Director, President, Chief Operating Officer
/s/ David T. Merrill DAVID T. MERRILL	Chief Financial Officer and Treasurer (Principal Financial Officer)

/s/ Stanley W. Belitz STANLEY W. BELITZ	Controller (Principal Accounting Officer)
/s/ J. Michael Adcock J. MICHAEL ADCOCK	Director
/s/ Don Cook DON COOK	Director
/s/ King P. Kirchner KING P. KIRCHNER	Director
/s/ Mark E. Monroe MARK E. MONROE	Director
/s/ William B. Morgan WILLIAM B. MORGAN	Director
/s/ John H. Williams JOHN H. WILLIAMS	Director
/s/ John S. Zink JOHN S. ZINK	Director

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23.2	Consent of Independent Petroleum Engineers.	
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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.	

CREDIT AGREEMENT

DATED AS OF JANUARY 30, 2004

AMONG

UNIT CORPORATION,
MOUNTAIN FRONT PIPELINE COMPANY, INC.,
UNIT DRILLING COMPANY,
UNIT PETROLEUM COMPANY,
PETROLEUM SUPPLY COMPANY,
SERDRILCO, INC.
and
UNIT ENERGY CANADA, INC.,

AS BORROWERS,

THE LENDERS,

BANK OF OKLAHOMA, NATIONAL ASSOCIATION,
AS ADMINISTRATIVE AGENT FOR THE LENDERS,
and as
AS SYNDICATION AGENT

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CREDIT AGREEMENT

THIS LOAN AGREEMENT, dated effective as of January 30, 2004 ("Agreement"), is entered into among UNIT CORPORATION, a Delaware corporation ("Unit"), MOUNTAIN FRONT PIPELINE COMPANY, INC., an Oklahoma corporation, UNIT DRILLING COMPANY, an Oklahoma corporation, UNIT PETROLEUM COMPANY, an Oklahoma corporation, PETROLEUM SUPPLY COMPANY, an Oklahoma corporation, SERDRILCO, INC., an Oklahoma corporation and UNIT ENERGY CANADA INC., an Alberta, Canada corporation, each with its principal place of business at 7130 South Lewis, Suite 100, Tulsa, Oklahoma 74136 (collectively the "Borrowers") and BANK OF OKLAHOMA, NATIONAL ASSOCIATION ("BOk"), BANK OF AMERICA, N.A. ("B of A"), BMO NESBITT BURNS FINANCING, INC. ("BMO"), and COMPASS BANK ("Compass") (BOk, B of A, BMO and Compass, each being sometimes referred to herein, individually, as a "Lender," and collectively as the "Lenders"); and BOk as agent for the Lenders now or hereafter signatory party to this Agreement (in such capacity, herein referred to as the "Agent").

W I T N E S S E T H:

WHEREAS, the Borrowers, BOk, as the agent for the Existing Lenders (defined herein), and the financial institutions named and defined therein as lenders signatory parties thereto (collectively, the "Existing Lenders") are parties to that certain Loan Agreement dated as of July 24, 2001 (the "Existing Credit Agreement"), pursuant to which the Existing Lenders provided certain loans and extensions of revolving credit to the Borrowers (all indebtedness arising and all obligations, including contingent liabilities on letters of credit issued pursuant to the Existing Credit Agreement are collectively called the "Existing Indebtedness"); and

WHEREAS, Unit is a party to that certain Agreement and Plan of Merger with PetroCorp. Incorporated ("PetroCorp"), dated as of August 14, 2003 (together with all schedules and exhibits thereto and all amendments, supplements, addenda and modifications, collectively the "PetroCorp Agreement") pursuant to which Unit will become the owner of all of the outstanding capital stock of PetroCorp; and

WHEREAS, Unit has requested the Syndication Agent to (i) arrange for the financing of the acquisition of PetroCorp and (ii) refinance any Existing Indebtedness; and WHEREAS, as a condition to obtaining the financing contemplated hereby, Borrowers have agreed to refinance any Existing Indebtedness in full with funds to be made available under this Agreement; and

WHEREAS, the parties hereto desire to appoint BOk as Administrative Agent for the Lenders, and Borrowers desire to obtain the Commitments (i) to refinance any Existing Indebtedness, (ii) to consummate the closing of the PetroCorp Agreement and acquisition of PetroCorp, and (iii) for other purposes permitted by the terms of this Agreement; and

WHEREAS, after giving effect to the refinancing of any Existing Indebtedness and extinguishment of the Commitments of the Existing Lenders and the replacement thereof by the

Commitments, the several (but not joint) Commitment (as herein defined) of each Lender hereunder will be as set forth on the Lenders Schedule; and

WHEREAS, pursuant to a separate agreement among BOk and Borrowers, BOk has been appointed Syndication Agent for the credit facilities provided in this Agreement;

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I

DEFINITIONS

1.1. Defined Terms. As used in this Agreement, the following terms have the meaning specified below or in the sections and subsections referred to below:

"Acquisition" means any transaction, or any series of related transactions, consummated on or after the date of this Agreement, by which the Borrowers or any of their Subsidiaries (i) acquires, by any means, any going business or all or substantially all of the assets of any Person or (ii) directly or indirectly acquires (in one transaction or as the most recent transaction in a series of transactions) at least a majority (in number of votes) of the securities of a corporation which have ordinary voting power for the election of directors (other than securities having such power only by reason of the happening of a contingency) or a majority (by percentage or voting power) of the outstanding ownership interests of a partnership or limited liability company.

"Administrative Agent" means BOk in its capacity as contractual agent of the Lenders pursuant to Article XIII, and any successor Administrative Agent under Article XIII.

"Advance" means a borrowing under Article II, (i) made by the Lenders on the same Borrowing Date, or (ii) converted or continued by the Lenders on the same date of conversion or continuation, consisting, in either case, of the aggregate amount of the several Loans of the same type (either Floating Rate Advance or Eurodollar Advance) and, in the case of Eurodollar Loans, for the same Interest Period.

"Affiliate" of any Person means any other Person directly or indirectly controlling, controlled by or under common control with such Person. A Person will be deemed to control another Person if the controlling Person owns 10% or more of any class of voting securities (capital stock, general or limited partnership units or interests, limited liability company membership interests or association or other business entity shares, participations, rights or other equivalent ownership interests, however designated) of the controlled Person or possesses, directly or indirectly, the power to direct or cause the direction of the management or policies of the controlled Person, whether through ownership of stock, by contract or otherwise.

"Agent Fee Letter" means the separate letter agreement between and among the Borrowers and the Administrative Agent setting forth the syndication fee and the annual agency fee arrangements.

"Aggregate Commitment" means the total of the Commitments of all Lenders, as adjusted from time to time pursuant to the terms hereof; provided that the Aggregate Commitment will never exceed the lesser of (i) the Borrowing Base, or (ii) the Maximum Credit Amount.

"Aggregate Outstanding Credit Exposure" means, at any time, the aggregate of the Outstanding Credit Exposure of all the Lenders.

"Agreement" means this Credit Agreement, as it may be amended, modified, supplemented or restated and in effect from time to time.

"Alternate Base Rate" means, for any day, a rate of interest per annum equal to the higher of (i) the Prime Rate for such day or (ii) the sum of the Federal Funds Effective Rate for such day plus one-half of one percent per annum (0.50%), based on the number of days elapsed in an actual 365-366 day year.

"Applicable Margin" means the percentage rate per annum set forth in the Pricing Schedule.

"Authorized Officer" means any of the president, the chief financial officer, any vice president, the treasurer or any assistant treasurer of the Borrowers, acting singly.

"Available Aggregate Commitment" means, at any time, the Aggregate Commitment then in effect minus the Aggregate Outstanding Credit Exposure at such time.

"BOk" means Bank of Oklahoma, National Association, and its successors.

"Borrowers" means Unit, and its Existing Subsidiaries, and their respective successors and assigns.

"Borrowing Base" means, at the particular time in question, either the amount provided for in Section 2.6.1 or the amount otherwise determined in accordance with the remaining provisions of Section 2.6.

"Borrowing Base Properties" means the Rigs and the oil and gas properties evaluated by Lenders for purposes of establishing the Borrowing Base.

"Borrowing Base Usage Percentage" means, for any day, the percentage equal to the quotient of (i) the Aggregate Outstanding Credit Exposure on such day, divided by (ii) the Borrowing Base as initially set by the Lenders under Section 2.6.1 (and as subsequently set by the Lenders under Section 2.6.2 or other provisions of Section 2.6 [excluding Section 2.6.3]).

"Borrowing Date" means a date on which an Advance is made hereunder.

"Borrowing Notice" is defined in Section 2.9.

"Business Day" means (i) with respect to any borrowing, payment or rate selection of Eurodollar Advances, a day (other than a Saturday or Sunday) on which banks generally are open in Tulsa, Oklahoma, and New York City for the conduct of substantially all of their commercial lending activities, interbank wire transfers can be made on the Fedwire system and dealings in United States dollars are carried on in the London interbank market and (ii) for all other purposes, a day (other than a Saturday or Sunday) on which banks generally are open in Tulsa, Oklahoma, for the conduct of substantially all of their commercial lending activities and interbank wire transfers can be made on the Fedwire system.

"Capitalized Lease" of a Person means any lease of Property by such Person as lessee which would be capitalized on a balance sheet of such Person prepared in accordance with GAAP.

"Capitalized Lease Obligations" of a Person means the amount of the obligations of such Person under Capitalized Leases which would be shown as a liability on a balance sheet of such Person prepared in accordance with GAAP.

"Cash Equivalent Investments" means (i) short-term obligations of, or fully guaranteed by, the United States of America, (ii) commercial paper rated A-1 or better by S&P or P-1 or better by Moody's, (iii) demand deposit accounts maintained in the ordinary course of business, and (iv) certificates of deposit issued by and time deposits with commercial banks (whether domestic or foreign) having capital and surplus in excess of $100,000,000; provided in each case that the same provides for payment of both principal and interest (and not principal alone or. interest alone) and is not subject to any contingency regarding the payment of principal or interest.

"Change in Control" means the acquisition by any Person, or two or more Persons acting in concert, of beneficial ownership (within the meaning of Rule 13d-3 of the Securities and Exchange Commission under the Securities Exchange Act of 1934) of 30% or more of the outstanding shares of voting stock of the Borrowers.

"Chase" means JPMorgan Chase Bank or any other financial institution that is the primary banking subsidiary of JPMorgan Chase & Company from time to time.

"Code" means the Internal Revenue Code of 1986, as amended, reformed or otherwise modified from time to time.

"Collateral" means all Property of Borrowers and their respective Subsidiaries in which a Lien has been granted under the Collateral Documents.

"Collateral Documents" means, collectively, the documents listed on the Security Schedule, including the Security Agreement, and all other deeds of trust, mortgages, assignments, security agreements, pledge agreements and other security documents from time to time delivered to Administrative Agent to secure the Secured Obligations.

"Commitment" means, for each Lender, the obligation of such Lender to make Loans to, and participate in LCs issued on the application of, the Borrowers in an aggregate amount not exceeding the amount set forth on the Lenders Schedule or as set forth in any Notice of Assignment relating to any assignment that has become effective under Section 14.3.2, as such amount may be modified from time to time under to the terms hereof; provided that no Lender's Commitment will ever exceed the lesser of such Lender's Pro Rata Share of (i) the Borrowing Base, or (ii) Maximum Credit Amount.

"Commitment Fee Rate" means, at any time, the per annum percentage rate at which commitment fees are accruing on the Available Aggregate Commitment under Section 2.5.3 at such time at the rate set forth in the Pricing Schedule.

"Consolidated EBITDA" means Consolidated Net Income plus, to the extent deducted from revenues in determining Consolidated Net Income, (i) Consolidated Interest Expense, (ii) expense for income and income based taxes paid or accrued, (iii) depreciation, depletion, amortization and impairment, including without limitation, impairment of goodwill, and (iv) any non-cash items associated with mark to market accounting, all calculated for the Borrowers and their Subsidiaries on a consolidated basis.

"Consolidated Interest Expense" means, for any period with respect to any Person, the amount which, in conformity with GAAP, would be set forth opposite the caption "interest expense" or any like caption (including without limitation, imputed interest included in payments under any Capitalized Lease) on a consolidated income statement of such Person and the Subsidiaries for such period excluding the amortization of any original issue discount.

"Consolidated Net Income" means, with reference to any period, the net income (or loss) of the Borrowers and their Subsidiaries calculated on a consolidated basis for such period.

"Consolidated Net Worth" means the sum of (a) the par value of Unit's consolidated capital stock (excluding treasury stock), plus (b) Unit's consolidated additional paid-in capital, plus (c) the amount of Unit's consolidated retained earnings.

"Contingent Obligation" of a Person means any agreement, undertaking or arrangement by which such Person assumes, guarantees, endorses, contingently agrees to purchase or provide funds for the payment of, or otherwise becomes or is contingently liable on, the obligation or liability of any other Person, or agrees to maintain the net worth or working capital or other financial condition of any other Person, or otherwise assures any creditor of such other Person against loss, including, without limitation, any comfort letter, take-or-pay contract or the obligations of any such Person as general partner of a partnership with respect to the liabilities of the partnership.

"Contingent Obligations Schedule" means Schedule 8.

"Controlled Group" means all members of a controlled group of corporations or other business entities and all trades or businesses (whether or not incorporated) under common

control which, together with the Borrowers or any of their respective Subsidiaries, are treated as a single employer under Section 414 of the Code.

"Conversion/Continuation Notice" is defined in Section 2.10.

"Credit Extension" means the making of an Advance or the issuance of a LC hereunder.

"Credit Extension Date" means the Borrowing Date for an Advance or the issuance date for a LC.

"Credit Parties" means, collectively, the Borrowers and the Material Subsidiaries (including the Subsidiary Guarantors), and "Credit Party" means any one of them.

"Default" means an event described in Article X.

"Determination Date" is defined in Section 2.6.2.

"Disclosure Schedule" means Schedule 3.

"Engineered Value" means, at the time of determination, the future net revenues of the oil and gas portion of the Borrowing Base Properties calculated by Administrative Agent and the Required Lenders using the pricing parameters and discount rate currently being used by Administrative Agent.

"Engineering Report" means the Initial Engineering Report and each engineering report delivered pursuant to Section 6.1.

"Environmental Laws" means any and all federal, state, local and foreign statutes, laws, judicial decisions, regulations, ordinances, rules, judgments, orders, decrees, plans, injunctions, permits, concessions, grants, franchises, licenses, agreements and other governmental restrictions relating to (i) the protection of the environment, (ii) the effect of the environment on human health, (iii) emissions, discharges or releases of pollutants, contaminants, hazardous substances or wastes into surface water, ground water or land, or (iv)

the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of pollutants, contaminants, hazardous substances or wastes or the clean-up or other remediation thereof.

"Equity" means shares of capital stock or a partnership, profits, capital, member or other equity interest, or options, warrants or any other rights to substitute for or otherwise acquire the capital stock or a partnership, profits, capital, member or other equity interest of any Person.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and any rule or regulation issued thereunder.

"Eurodollar Advance" means an Advance which, except as otherwise provided in Section 2.12, bears interest at the applicable Eurodollar Rate.

"Eurodollar Base Rate" means, with respect to a Eurodollar Advance for the relevant Interest Period: (a) the interest rate per annum equal to the rate determined by the Administrative Agent to be the offered rate that appears on the page of the Telerate Screen that displays an average British Bankers' Association Interest Settlement Rate (such page currently being page number 3750) for deposits in U.S. dollars (for delivery on the first day of such Interest Period) as reported by any generally recognized financial information service, determined as of approximately 11:00 a.m. (London time) three (3) Business Days prior to the first day of such Interest Period, and having a term equivalent to such Interest Period, provided that, in the event the rate referenced in subsection (a) does not appear on such page or such service is not available to the Administrative Agent, the applicable Eurodollar Base Rate for the relevant Interest Period will instead be the rate determined by the Administrative Agent to be the rate at which Chase or one of its Affiliate banks offers to place deposits in U.S. dollars with first-class banks in the London interbank market at approximately 11:00 a.m. (London time) three (3) Business Days prior to the first day of such Interest Period, in the approximate amount of BOk's relevant Eurodollar Loan and having a maturity equal to such Interest Period.

"Eurodollar Loan" means a Loan which, except as otherwise provided in Section 2.12, bears interest at the applicable Eurodollar Rate.

"Eurodollar Rate" means, with respect to any Interest Period, an interest rate per annum equal to the sum of (i) the quotient of (a) the Eurodollar Base Rate applicable to such Interest Period, divided by (b) one minus the Reserve Requirement (expressed as a decimal) applicable to such Interest Period, plus (ii) the Applicable Margin, based on a 360 day year.

"Excluded Accounts" has the meaning assigned in Section 6.11(a).

"Excluded Taxes" means, in the case of each Lender and the Administrative Agent, taxes imposed on its overall net income, and franchise taxes imposed on it, by (i) the jurisdiction under the laws of which such Lender or the Administrative Agent is incorporated or organized or (ii) the jurisdiction in which the Administrative Agent's or such Lender's principal executive office is located.

"Existing Indebtedness " has the meaning assigned to such term in the recitals hereto.

"Existing Subsidiaries" means Mountain Front Pipeline Company, Inc., an Oklahoma corporation, Unit Drilling Company, an Oklahoma corporation, Unit Petroleum Company, an Oklahoma corporation, Petroleum Supply Company, an Oklahoma corporation, SerDrilco, Inc., an Oklahoma corporation, and Unit Energy Canada, Inc., an Alberta, Canada corporation

"Facility Termination Date" mean the date which is four (4) years from the date of this Agreement, or any earlier date on which the Aggregate Commitment is reduced to zero or otherwise terminated pursuant to the terms of this Agreement.

"Federal Funds Effective Rate" means, for any day, an interest rate per annum equal to the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers on such day, as published for such

day (or, if such day is not a Business Day, for the immediately preceding Business Day) by the Federal Reserve Bank of New York, or, if such rate is not

so published for any day which is a Business Day, the average of the quotations at approximately 10:00 a.m. (Tulsa time) on such day on such transactions received by the Administrative Agent from three Federal funds brokers of recognized standing selected by the Administrative Agent in its sole discretion.

"Financial Contract" of a Person means (i) any exchange-traded or over-the-counter futures, forward, swap, hedge or option contract or other financial instrument with similar characteristics, and (ii) any Rate Management Transaction.

"Floating Rate" means, for any day, a rate per annum equal to the Alternate Base Rate for such day, in each case changing when and as the Alternate Base Rate changes.

"Floating Rate Advance" means an Advance which, except as otherwise provided in Section 2.12, bears interest at the Floating Rate.

"Floating Rate Loan" means a Loan which, except as otherwise provided in Section 2.12, bears interest at the Floating Rate.

"GAAP" means generally accepted accounting principles as in effect from time to time in the United States, applied in a manner consistent with that used in preparing the financial statements referred to in Section 5.4.

"Highest Lawful Rate" means, on any day with respect to each Lender to whom Obligations are owed, the maximum nonusurious rate of interest that such Lender is permitted under applicable law to contract for, take, charge or receive with respect to such Obligations for such day. All determinations herein of the Highest Lawful Rate, or of any interest rate determined by reference to the Highest Lawful Rate, will be made separately for each Lender as appropriate to assure that the Loan Documents are not construed to obligate any Person to pay interest to any Lender at a rate in excess of the Highest Lawful Rate applicable to such Lender.

"Indebtedness" of a Person means such Person's (i) obligations for borrowed money, (ii) obligations representing the deferred purchase price of Property or services (other than accounts payable arising in the ordinary course of such Person's business payable on terms customary in the trade), (iii) obligations, whether or not assumed, secured by Liens or payable out of the proceeds or production from Property now or hereafter owned or acquired by such Person (other than Permitted Encumbrances), (iv) obligations which are evidenced by notes, acceptances, or other instruments, (v) obligations of such Person to purchase securities or other Property arising out of or in connection with the sale of the same or substantially similar securities or Property, (vi) Capitalized Lease Obligations, (vii) Contingent Obligations, (viii) Rate Management Obligations, (ix) obligations to reimburse issuers of Letters of Credit, (x) obligations with respect to payments received in consideration of oil, gas, or other minerals yet to be acquired or produced at the time of payment (including obligations under "take-or-pay" contracts to deliver gas in return for payments already received and the undischarged balance of any production payment created by such Person or for the creation of which such Person directly or indirectly received payment), (xi) obligations with respect to other obligations to deliver goods or services

in consideration of advance payments therefor; and (xii) any other obligation for borrowed money or other financial accommodation which in accordance with GAAP would be shown as a liability on the consolidated balance sheet of such Person.

"Initial Engineering Report" means the engineering reserve report concerning oil and gas properties of PetroCorp prepared by PetroCorp as of July 1, 2003 and the engineering reserve report concerning oil and gas properties of Unit and the Existing Subsidiaries prepared by Unit or its Existing Subsidiaries and audited by Ryder Scott Company as of December 31, 2002.

"Interest Period" means, with respect to a Eurodollar Advance, a period of one, two, three or six months commencing on a Business Day selected by Unit pursuant to this Agreement. Such Interest Period will end on the day which corresponds numerically to such date one, two, three or six months thereafter, provided, however, that if there is no such numerically corresponding day in the next, second, third or sixth succeeding month, such Interest Period will end on the last Business Day of the next, second, third or sixth succeeding month. If an Interest Period would otherwise end on a day which is not a Business Day, such Interest Period will end on the next succeeding Business Day, provided, however, that if the next succeeding Business Day falls in a new calendar month, such Interest Period will end on the immediately preceding Business Day.

"Investment" of a Person means any loan, advance (other than commission, travel and similar advances to officers and employees made in the ordinary course of business), extension of credit (other than accounts receivable arising in the ordinary course of business on terms customary in the trade) or contribution of capital by such Person; stocks, bonds, mutual funds, partnership interests, notes, debentures or other securities owned by such Person; any deposit accounts and certificate of deposit owned by such Person; and structured notes, derivative financial instruments and other similar instruments or contracts owned by such Person.

"LC" is defined in Section 2.19.1.

"LC Application" is defined in Section 2.19.3.

"LC Fee" is defined in Section 2.19.4.

"LC Issuer" means BOk (or any subsidiary or affiliate of BOk designated by BOk) or any other Lender in its capacity as issuer of LCs hereunder.

"LC Obligations" means, at any time, the sum, without duplication, of (i) the aggregate undrawn stated amount under all LCs outstanding at such time plus (ii) the aggregate unpaid amount at such time of all Reimbursement Obligations.

"LC Payment Date" is defined in Section 2.19.5.

"Lenders" means the lending institutions now or hereafter listed on the signature pages of this Agreement and their respective successors and assigns.

"Lenders Schedule" means Schedule 2.

"Letter of Credit" of a Person means a letter of credit or similar instrument which is issued upon the application of such Person or upon which such Person is an account party or for which such Person is in any way liable.

"Lien" means any lien (statutory or other), mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance or preference, priority or other security agreement or preferential arrangement of any kind or nature whatsoever (including, without limitation, the interest of a vendor or lessor under any conditional sale, Capitalized Lease or other title retention agreement).

"Loan" means, with respect to a Lender, that Lender's Advances made pursuant to Article II (or any conversion or continuation thereof).

"Loan Documents" means this Agreement, the LC Applications and any Notes issued pursuant to Section 2.14, the Collateral Documents and each Subsidiary Guaranty.

"Long Term Debt" means all outstanding long term liabilities of the Borrowers in accordance with GAAP excluding deferred taxes and the plugging and abandonment accrued liabilities described in Section 7.9(v).

"Material Adverse Effect" means a material adverse effect on (i) the business, Property, condition (financial or otherwise), results of operations, or prospects of the Borrowers and their Subsidiaries taken as a whole (taking into account the present value of any indemnification in favor of the Borrowers or any applicable insurance coverage), (ii) the ability of any of the Borrowers to perform their obligations under the Loan Documents to which it is a party, or (iii) the validity or enforceability of any of the Loan Documents or the rights or remedies of the Administrative Agent, the LC Issuer or the Lenders thereunder.

"Material Indebtedness" means Indebtedness in an outstanding principal amount of $1,000,000 or more in the aggregate (or the equivalent thereof in any currency other than U.S. dollars).

"Material Indebtedness Agreement" means any agreement under which any Material Indebtedness was created or is governed or which provides for the incurrence of Indebtedness in an amount which would constitute Material Indebtedness (whether or not an amount of Indebtedness constituting Material Indebtedness is outstanding thereunder).

"Material Subsidiary" means at any time a Subsidiary of any of the Borrowers having (i) at least ten percent (10%) of the consolidated total assets of the Borrowers and their Subsidiaries (determined as of the last day of the

most recent fiscal quarter of the Borrowers) or (ii) at least ten percent (10%) of the consolidated revenues of the Borrowers and their Subsidiaries for the fiscal year of the Borrowers then most recently ended.

"Maximum Credit Amount" means such amount that is agreed to in writing by the Borrowers and the Lenders as the maximum amount of Credit Extensions available to the Borrowers under Article II of this Agreement from Lenders.

"Modify" and "Modification" are defined in Section 2.19.1.

"Moody's" means Moody's Investors Service, Inc.

"Multiemployer Plan" means a Plan maintained pursuant to a collective bargaining agreement or any other arrangement to which the Borrowers or any member of the Controlled Group is a party to which more than one employer is obligated to make contributions.

"Note" is defined in Section 2.14.

"Obligations" means all unpaid principal of and accrued and unpaid interest on the Loans, all Reimbursement Obligations, all accrued and unpaid fees and all expenses, reimbursements, indemnities and other obligations of the Borrowers to the Lenders or to any Lender, the Administrative Agent, the LC Issuer or any indemnified party arising under the Loan Documents.

"Other Taxes" is defined in Section 3.3(ii).

"Outstanding Credit Exposure" means, as to any Lender at any time, the sum of (i) the aggregate principal amount of its Loans outstanding at such time, plus (ii) an amount equal to its Pro Rata Share of the LC Obligations at such time.

"Participants" is defined in Section 14.2.1.

"Payment Date" means the last day of each fiscal quarter of Unit (insofar as Eurodollar Loans are concerned) and the last day of each month (insofar as Floating Rate Loans are concerned).

"PBGC" means the Pension Benefit Guaranty Corporation, or any successor thereto.

"Permitted Encumbrances" means any Lien permitted by Section 7.6.

"Person" means any natural person, corporation, firm, joint venture, partnership, limited liability company, association, enterprise, trust or other entity or organization, or any government or political subdivision or any agency, department or instrumentality thereof.

"PetroCorp" means PetroCorp Incorporated, a Texas corporation.

"PetroCorp Agreement" means the Agreement and Plan of Merger dated as of August 14, 2003, among PetroCorp, Unit and Unit Acquisition Company, a Texas corporation, as amended, modified or restated, together with all schedules, exhibits and addenda thereto.

"Plan" means an employee pension benefit plan which is covered by Title IV of ERISA or subject to the minimum funding standards under Section 412 of the Code as to which the Borrowers or any member of the Controlled Group may have any liability.

"Pricing Schedule" means Schedule 1.

"Prime Rate" means a rate per annum equal to the prime rate of interest announced from time to time by Chase (which is not necessarily the lowest rate charged to any customer), changing when and as said prime rate changes.

"Pro Rata Share" means, with respect to a Lender, a portion equal to a fraction the numerator of which is such Lender's Commitment and the denominator of which is the Aggregate Commitment.

"Property" of a Person means any and all property, whether real, personal, tangible, intangible, or mixed, of such Person, or other assets owned, leased or operated by such Person.

"Purchasers" is defined in Section 14.3.1.

"Rate Management Obligations" of a Person means any and all obligations of such Person, whether absolute or contingent and howsoever and whensoever created, arising, evidenced or acquired (including all renewals, extensions, supplements, replacements and modifications thereof and substitutions therefor), under (i) any and all Rate Management Transactions, and (ii) any and all cancellations, buy backs, reversals, terminations or assignments of any Rate Management Transactions.

"Rate Management Transaction" means any transaction (including an agreement with respect thereto) now existing or hereafter entered by the Borrowers which is a rate swap, basis swap, hedge, forward rate transaction, commodity swap, commodity option, equity or equity index swap, equity or equity index option, bond option, interest rate option, foreign exchange transaction, cap transaction, floor transaction, collar transaction, forward transaction, currency swap transaction, cross-currency rate swap transaction, currency option or any other similar transaction or price/commodity protection device (including any option with respect to any of these transactions) or any combination thereof, whether linked to one or more interest rates, foreign currencies, commodity prices, equity prices or other financial measures. Notwithstanding the foregoing, a "Rate Management Transaction" will not include any contract for the purchase and sale of natural gas or oil entered into in the ordinary course of business and on customary trade terms.

"Redetermination" means a Scheduled Redetermination or a Special Redetermination.

"Regulation D" means Regulation D of the Board of Governors of the Federal Reserve System as from time to time in effect and any successor thereto or other regulation or official interpretation of said Board of Governors relating to reserve requirements applicable to member banks of the Federal Reserve System.

"Regulation U" means Regulation U of the Board of Governors of the Federal Reserve System as from time to time in effect and any successor or other regulation or official interpretation of said Board of Governors relating to the extension of credit by banks for the purpose of purchasing or carrying margin stocks applicable to member banks of the Federal Reserve System.

"Reimbursement Obligations" means, at any time, the aggregate of all obligations of the Borrowers then outstanding under Section 2.19 to reimburse the LC Issuer for amounts paid by the LC Issuer in respect of any one or more drawings under LCs.

"Reportable Event" means a reportable event as defined in Section 4043 of ERISA, with respect to which the notice requirements to the PBGC have not been waived, provided, however, that a failure to meet the minimum funding standard of Section 412 of the Code and of Section 302 of ERISA will be a Reportable Event regardless of the issuance of any such waiver of the notice requirement in accordance with either Section 4043(a) of ERISA or Section 412(d) of the Code.

"Required Lenders" means Lenders in the aggregate having at least 75% of the Aggregate Commitment or, if the Aggregate Commitment has been terminated, Lenders in the aggregate holding at least 75% of the Aggregate Outstanding Credit Exposure.

"Reserve Requirement" means, with respect to an Interest Period, the maximum aggregate reserve requirement (including all basic, supplemental, marginal and other reserves) which is imposed under Regulation D on Eurocurrency liabilities.

"Rigs" means the drilling rigs and related equipment, machinery, accessories and other personal property rights or interests encumbered by the Security Documents.

"S&P" means Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.

"Sale and Leaseback Transaction" means any sale or other transfer of Property by any Person with the intent to lease such Property as lessee.

"Scheduled Redetermination" means any redetermination of the Borrowing Base under Sections 2.6.4 or 2.6.5 in accordance with Section 2.6.2.

"SEC" means the Securities and Exchange Commission.

"Security Schedule" means Schedule 4.

"Secured Obligations" means, collectively, (i) the Obligations and (ii) all Rate Management Obligations owing to one or more Lenders or any affiliates of the Lenders.

"Single Employer Plan" means a Plan maintained by the Borrowers or any member of the Controlled Group for employees of the Borrowers or any member of the Controlled Group.

"Special Redetermination" means any redetermination of the Borrowing Base pursuant to Sections 2.6.4 or 2.6.5.

"Subsidiary" of a Person means (i) any corporation more than 50% of the outstanding securities having ordinary voting power of which will at the time be owned or controlled, directly or indirectly, by such Person or by one or more of their Subsidiaries or by such Person and one or more of their Subsidiaries, or (ii) any partnership, limited liability company, association, joint venture or similar business organization more than 50% of the ownership interests having ordinary voting power of which will at the time be so owned or controlled, provided that associations, joint ventures or other relationships (a) which are established pursuant to a standard form operating agreement or similar agreement or which are partnerships for purposes of federal income taxation only, (b) which are not corporations or partnerships (or subject to the Uniform Partnership Act) under applicable state applicable law, and (c) whose businesses are limited to the exploration, development and operation of oil, gas or mineral properties and interests owned directly by the parties in such associations, joint ventures or relationships, will not be deemed to be "Subsidiaries" of such Person. Unless otherwise expressly provided, all references herein to a "Subsidiary" will mean a Subsidiary of any of the Borrowers (including Subsidiary Guarantors).

"Subsidiary Guarantor" means PetroCorp (upon consummation of the PetroCorp Agreement) and each other present or future Material Subsidiary and their successors and assigns.

"Subsidiary Guaranty" means the Guaranty Agreement, substantially in the form of Exhibit E to be executed by each Material Subsidiary in favor of the Administrative Agent for the ratable benefit of the Lenders, with respect to the Obligations of the Borrowers under this Credit Agreement.

"Subsidiary Guaranty Joinder Agreement" means the Joinder Agreement, substantially in the form of Schedule 1 to the Subsidiary Guaranty, to be executed and delivered by each new Material Subsidiary in accordance with the provisions of Section 9.4 of this Credit Agreement.

"Syndication Agent" means BOk and its successors and assigns.

"Taxes" means any and all present or future taxes, duties, levies, imposts, deductions, charges or withholdings, and any and all liabilities with respect to the foregoing, but excluding Excluded Taxes and Other Taxes.

"Transferee" is defined in Section 14.4.

"Unfunded Liabilities" means the amount (if any) by which the present value of all vested and unvested accrued benefits under all Single Employer Plans exceeds the fair market value of all such Plan assets allocable to such benefits, all determined as of the then most recent valuation date for such Plans using PBGC actuarial assumptions for single employer plan terminations.

"Wholly-Owned Subsidiary" of a Person means (i) any Subsidiary all of the outstanding voting securities of which will at the time be owned or controlled, directly or indirectly, by such

Person or one or more Wholly-Owned Subsidiaries of such Person, or by such Person and one or more Wholly-Owned Subsidiaries of such Person, or (ii) any partnership, limited liability company, association, joint venture or similar business organization 100% of the ownership interests having ordinary voting power of which will at the time be so owned or controlled.

The foregoing definitions will be equally applicable to both the singular and plural forms of the defined terms.

1.2. Exhibits and Schedules; Additional Definitions. All Exhibits and Schedules attached to this Agreement are a part of this Agreement for all purposes. Reference is hereby made to the Security Schedule for the meaning of certain terms defined therein and used but not defined herein, which definitions are incorporated herein by reference.

1.3. Amendment of Defined Instruments. Unless the context otherwise requires or unless otherwise provided in this Agreement the terms defined in this Agreement which refer to a particular agreement, instrument or document also refer to and include all renewals, extensions, modifications, amendments and restatements of such agreement, instrument or document, provided that nothing in this section will be construed to authorize any such renewal, extension, modification, amendment or restatement.

1.4. Reference and Titles. All references in this Agreement to Exhibits, Schedules, articles, sections, subsections and other subdivisions refer to the Exhibits, Schedules, articles, sections, subsections and other subdivisions of this Agreement unless expressly provided otherwise. Exhibits and Schedules to any Loan Document will be deemed incorporated by reference in such Loan Document. References to any document, instrument, or agreement (a) will include all exhibits, schedules, and other attachments thereto, and (b) will include all documents, instruments, or agreements issued or executed in replacement or restatement thereof. Titles appearing at the beginning of any subdivisions are for convenience only and do not constitute any part of such subdivisions and will be disregarded in construing the language contained in such subdivisions. The words "this Agreement," "this instrument," "herein," "hereof," "hereby," "hereunder" and words of similar import refer to this Agreement as a whole and not to any particular subdivision unless expressly so limited. The phrases "this section" and "this subsection" and similar phrases refer only to the sections or subsections hereof in which such phrases occur. The word "or" is not exclusive, and the word "including" (in its various forms) means "including without limitation." Pronouns in masculine, feminine and neuter genders will be construed to include any other gender, and words in singular form will be construed to include the plural and vice versa, unless the context otherwise requires.

1.5 Accounting Terms and Determinations. Except only as otherwise expressly provided in this Agreement, all accounting terms will be interpreted, and all financial statements and certificates and reports as to financial matters required to be delivered to the Administrative Agent or the Lenders under this Agreement shall be prepared in accordance with GAAP, as applied on a consistent basis. References to "days" will mean calendar days, unless the term "Business Day" is used. Unless otherwise specified, references herein to any particular Person also refer to its successors and permitted assigns.

1.6. Calculations and Determinations. All calculations under the Loan Documents of interest and of fees will be made on the basis of actual days elapsed (including the first day but excluding the last) and a year of 360 days except only for interest accruals on Floating Rate Loans which will be based on the number of days lapsed in a 365-366 day year. Each determination by a Lender of amounts to be paid under Article III or any other matters which are to be determined hereunder by a Lender (such as any Eurodollar Rate, Business Day, Interest Period, or Reserve Requirement) will, in the absence of manifest error, be conclusive and binding.

1.7. Joint Preparation; Construction of Indemnities and Releases. This Agreement and the other Loan Documents have been reviewed and negotiated by sophisticated parties with access to legal counsel and no rule of construction will apply hereto or thereto which would require or allow any Loan Document to be construed against any party because of its role in drafting such Loan Document. All indemnification and release provisions of this Agreement will be construed broadly (and not narrowly) in favor of the Persons receiving indemnification or being released.

ARTICLE II

THE CREDITS

2.1. Commitments. From and including the date of this Agreement and up to the Facility Termination Date, each Lender severally agrees, on the terms and conditions of this Agreement, to (i) make Loans to the Borrowers (on a joint and several liability basis) and (ii) participate in LCs issued on the request of the Borrowers, provided that, after giving effect to the making of each such Loan and the issuance of each such LC, such Lender's Outstanding Credit Exposure

does not exceed its Commitment and the Aggregate Outstanding Credit Exposure does not exceed the Aggregate Commitment. Subject to the terms of this Agreement, Unit, as the designated borrowing agent on behalf of all of the Borrowers, may borrow, repay and reborrow at any time before the Facility Termination Date. Each Lender's Commitment will expire on the Facility Termination Date. The LC Issuer will issue LCs hereunder on the terms and conditions set forth in Section 2.19.

2.2. Required Payments; Termination. All unpaid Obligations will be paid in full by the Borrowers on the Facility Termination Date.

2.3. Ratable Loans. Each Advance will be made by the Lenders ratably according to their Pro Rata Shares.

2.4. Types of Advances. The Advances may be Floating Rate Advances or Eurodollar Advances, or a combination thereof, selected by Unit on behalf of the Borrowers in accordance with Sections 2.9 and 2.10.

2.5. Facility Fee; Initial Aggregate Commitment; Maximum Credit Amount; Commitment Fee Rate.

2.5.1. A facility fee of $451,500 will be paid at Closing to the Administrative Agent for the Pro Rata Share benefit of each Lender.

2.5.2. The initial Aggregate Commitment is $120,000,000 and the initial Maximum Credit Amount is $150,000,000. Any increase in either the Aggregate Commitment or the Maximum Credit Amount requires the written consent of all Lenders, except only for increases in the Aggregate Commitment to an amount not more than the Maximum Credit Amount in accordance with Section 14.6.

2.5.3. The Borrowers agree to pay to the Administrative Agent for the Pro Rata Share of each Lender a per annum Commitment Fee Rate (as set forth on the Pricing Schedule) on the average daily amount of the Available Aggregate Commitment from the date of this Agreement through the Facility Termination Date. The Commitment Fee Rate will be payable on each quarterly Payment Date hereafter and on the Facility Termination Date. All accrued commitment fees will be payable on the effective date of any termination of the obligations of the Lenders to make Credit Extensions.

2.6. Borrowing Base.

2.6.1. Until the first Determination Date, the parties hereto stipulate that the Borrowing Base preliminarily set by the Lenders is $188,000,000 (including a stipulated $20,000,000 for the Rigs), subject to the term, provisions and limitations hereof (the "Borrowing Base"). Each Borrowing Base determination will include $20,000,000 as the loan value for the Rigs.

2.6.2. By April 1 and October 1 of each year beginning April 1, 2004 Unit will furnish to each Lender all information, reports and data that Administrative Agent has then requested concerning the businesses and properties (including the information specified in Sections 6.1(vii) and (viii)). The Engineering Report submitted to each Lender by each April 1 will be audited by an independent third party engineering firm acceptable to the Agent and dated no earlier than December 31 of the immediately preceding calendar year. The Engineering Report submitted to the Lenders by October 1 will be internally prepared by Unit and dated no earlier than June 30 of such year and:

(a) By each May 10 and November 10, commencing May 10, 2004, the Administrative Agent will submit to the Lenders its proposed Borrowing Base amount

(b) Any Lender who objects to the Administrative Agent's proposed redetermination of the amount of the Borrowing Base must notify the Administrative Agent in writing within fifteen (15) days after it receives the Administrative Agent's notice of the proposed redetermined Borrowing Base, or it will be deemed to have conclusively approved such proposed redetermined Borrowing Base. The objecting Lender will also provide the Administrative Agent with a copy of its calculations and

determination of the Borrowing Base. If the Required Lenders do not agree on the redetermined Borrowing Base, the Administrative Agent will poll all Lenders and establish the Borrowing Base at the largest (highest) amount approved by the Required Lenders. Notwithstanding the foregoing, in no event will the redetermined Borrowing Base be increased above the previously determined Borrowing Base without the written consent of all Lenders.

(c) The Administrative Agent will then promptly notify Unit of the new Borrowing Base amount as determined by the Lenders. Unless within five (5) Business Days following the Administrative Agent's notice, Unit makes a designation permitted by Section 2.6.3, the new Borrowing Base will be effective as of the date such notice is sent (a "Determination Date"). If Unit so designates a lesser amount for the Borrowing Base, such designated Borrowing Base shall become effective when the Administrative Agent receives Unit's written designation, and in either event, the Borrowing Base will remain in effect until but not including the next date the Borrowing Base is redetermined other than designations permitted by Section 2.6.3.

(d) If Borrowers do not furnish all such information, reports and data by the date specified in this subsection, Administrative Agent may designate the Borrowing Base at any amount which Required Lenders determine and may redesignate the Borrowing Base from time to time until each Lender receives all such information, reports and data, at which time the Required Lenders may designate a new Borrowing Base. Required Lenders will determine the Borrowing Base based on (i) the loan value which they in their discretion assign to the various Borrowers' oil and gas properties being evaluated, (ii) the stipulated $20,000,000 Loan Value assigned to the Rigs, and (iii) any other credit factors (including without limitation the assets, liabilities, cash flow, hedged and unhedged exposure to price, foreign exchange rate, and interest rate changes, business, properties, prospects, management and ownership of Borrowers and their Subsidiaries) as the Lenders deem significant. The Lenders and the Administrative Agent have no obligation to agree on or designate the Borrowing Base at any particular amount, whether in relation to the Aggregate Commitment or otherwise.

2.6.3. Following the Administrative Agent's notice to Unit of the Borrowing Base amount determined under Section 2.6.2, Unit, on behalf of the Borrowers, may from time to time designate in writing to the Administrative Agent a reduced Aggregate Commitment amount subject to a minimum reduction amount of $10,000,000 (and in additional multiples of $10,000,000). Subject to any Special Redetermination permitted by this Section 2.6 and the provisions of this Section 2.6.3, such lesser amount designated by Unit will be the Aggregate Commitment until the next Scheduled Redetermination. The Administrative

Agent and the Lenders stipulate that Unit has initially designated $120,000,000 as the Aggregate Commitment effective from the date of this Agreement.

2.6.4 In addition to Scheduled Redeterminations, Required Lenders will be permitted to make a Special Redetermination of the Borrowing Base once between each Determination Date by notifying the Administrative Agent and Borrowers. Such Special Redetermination by the Lenders shall be in addition to any reduction of the Borrowing Base by the Required Lenders under Section 7.4(iv).

2.6.5. In addition to Scheduled Redeterminations, Borrowers will be permitted to request a Special Redetermination of the Borrowing Base once between each Determination Date. Such request, including the amount requested, will be submitted in writing to the to Administrative Agent and, at the time of such request, Unit will deliver to Administrative Agent and each Lender, any information they may reasonably request in connection with the request for a Special Redetermination.

2.6.6. If at any time, the Aggregate Outstanding Credit Exposure exceeds the lesser of the Borrowing Base or the Aggregate Commitment (a "Deficiency") because of a reduction in the Borrowing Base due to

or resulting from a redetermination in accordance with this Section 2.6, Administrative Agent may notify Unit in writing of the Deficiency and within ten (10) days from the date of such deficiency notice, Unit will elect one of the following options:

(a) Make a prepayment on the Notes in an amount sufficient to reduce the aggregate unpaid principal balance of the Notes by an amount equal to or more than the amount of such Deficiency; or

(b) Dedicate to this Agreement other oil and gas properties or assets not then included in the Borrowing Base determinations in form and substance satisfactory to the Required Lenders and the Administrative Agent as additional security for the Outstanding Credit Exposure and the Commitments (and all other Obligations), provided that such oil and gas properties are acceptable to the Required Lenders and are of a value, as determined by the Administrative Agent and the Required Lenders, that the Aggregate Outstanding Credit Exposure does not exceed the Borrowing Base (as adjusted to include the values of the additional oil and gas properties); or

(c) Commence monthly principal payments each equal to the amount of the Deficiency divided by the number of whole calendar months between date of the Deficiency notice and the next semi-annual Scheduled Redetermination.

If Unit elects to (i) make a prepayment on the Notes under clause (a) or (ii) commence monthly principal payments under clause (c), such prepayment will be due within twenty (20) days after the date of Unit's timely election. The prepayment or monthly principal payments will be applied in reduction of the principal balance of the Notes. If Unit elects to commit additional oil and gas properties under clause (b) above, the Borrowers will provide the Administrative Agent with descriptions of additional oil and gas properties (together with any current valuations and engineering reports applicable thereto which may be requested by the Administrative Agent) and will execute, acknowledge and deliver to the Administrative Agent any supplemental security agreements or pledges within thirty (30) days after the documents are tendered to the Borrowers by the Administrative Agent for execution.

2.7. Minimum Amount of Each Advance. Each Eurodollar Advance will be in the minimum amount of $2,000,000 (and in additional multiples of $1,000,000), and each Floating Rate Advance will be in the minimum amount of $100,000 (and in additional multiples of $100,000), provided, that any Floating Rate Advance may be in the amount of the Available Aggregate Commitment.

2.8. Principal Payments.

(a) Optional Principal Payments. The Borrowers may from time to time pay, without penalty or premium, all outstanding Floating Rate Advances, or, in a minimum aggregate amount of $100,000 or any multiple of $100,000 in excess thereof, any portion of the outstanding Floating Rate Advances upon notice to the Administrative Agent . The Borrowers may from time to time pay, subject to the payment of any funding indemnification amounts required by Section 3.5 but without penalty or premium, all outstanding Eurodollar Advances, or, in a minimum aggregate amount of $1,000,000 or any integral multiple of $1,000,000 in excess thereof, any portion of the outstanding Eurodollar Advances upon three (3) Business Days' prior notice to the Administrative Agent.

(b) Mandatory Principal Payments. If at any time a Deficiency occurs as a result of the sale or disposition of any Borrowing Base Properties (as opposed to a Deficiency subject to the provisions of Section 2.6.6 hereof), Borrowers will within 30 days after Administrative Agent gives notice of such fact to Borrowers to prepay the principal of the Loans in an aggregate amount at least equal to such Deficiency (or, if the Loans have been paid in full, deposit with the Administrative Agent the amount required to eliminate the Deficiency) together with interest during the period of such Deficiency at the Prime Rate per annum or Eurodollar Rate plus the Applicable Margin (calculated in the Pricing Schedule) per annum. Each payment of principal under this Section 2.8(b) will be accompanied by all interest then accrued and unpaid on the principal so prepaid. Any principal or interest prepaid pursuant to this section will be in addition to, and not in lieu of, all payments otherwise required to be paid under the Loan

Documents at the time of such prepayment.

2.9. Method of Selecting Loan Types and Interest Periods for New Advances. Unit will select the type of Advance and, in the case of each Eurodollar Advance, the Interest Period applicable thereto from time to time. Unit will give the Administrative Agent irrevocable notice (a "Borrowing Notice") not later than 12:00 noon (Tulsa time) on the same Business Day as the Borrowing Date of each Floating Rate Advance and three Business Days before the Borrowing Date for each Eurodollar Advance, specifying:

(i) the Borrowing Date, which will be a Business Day, of such Advance,

(ii) the aggregate amount of such Advance,

(iii) the type (Floating Rate or Eurodollar) of Advance selected, and

(iv) in the case of each Eurodollar Advance, the Interest Period applicable thereto.

Not later than 1 p. m. (Tulsa, Oklahoma time) on each Borrowing Date, each Lender will make available its Loan or Loans in funds immediately available in Tulsa to the Administrative Agent at its address specified pursuant to Article XV. The Administrative Agent will make the funds so received from the Lenders available to the Borrowers at the Administrative Agent's aforesaid address.

2.10. Conversion and Continuation of Outstanding Advances. Floating Rate Advances will continue as Floating Rate Advances unless and until such Floating Rate Advances are converted into Eurodollar Advances pursuant to this Section 2.10 or are repaid in accordance with Section 2.8. Each Eurodollar Advance will continue as a Eurodollar Advance until the end of the then applicable Interest Period therefor, at which time such Eurodollar Advance will be automatically converted into a Floating Rate Advance unless (x) such Eurodollar Advance is or was repaid in accordance with Section 2.8 or (y) Unit will have given the Administrative Agent a Conversion/Continuation Notice (as defined below) requesting that, at the end of such Interest Period, such Eurodollar Advance continue as a Eurodollar Advance for the same or another Interest Period. Subject to the terms of Section 2.7, Unit may elect from time to time to convert all or any part of a Floating Rate Advance into a Eurodollar Advance. Unit will give the Administrative Agent irrevocable notice (a "Conversion/Continuation Notice") of each conversion of a Floating Rate Advance into a Eurodollar Advance or continuation of a Eurodollar Advance not later than 12:00 noon (Tulsa time) at least three Business Days prior to the date of the requested conversion or continuation, specifying:

(i) the requested date, which will be a Business Day, of such conversion or continuation,

(ii) the aggregate amount and type of the Advance (floating Rate Advance or Eurodollar Advance) which is to be converted or continued, and

(iii) the amount of such Advance which is to be converted into or continued as a Eurodollar Advance and the duration of the Interest Period applicable thereto.

2.11. Changes in Interest Rate. Each Floating Rate Advance will bear interest on the outstanding principal amount thereof, for each day from and including the date such Advance is made or is automatically converted from a Eurodollar Advance into a Floating Rate Advance pursuant to Section 2.10, to but excluding the date it is paid or is converted into a Eurodollar Advance pursuant to Section 2.10 hereof, at a rate per annum equal to the Floating Rate for such day. Changes in the rate of interest on that portion of any Advance maintained as a Floating Rate Advance will take effect simultaneously with each change in the Alternate Base Rate. Each Eurodollar Advance will bear interest on the outstanding principal amount thereof from and including the first day of the Interest Period applicable thereto to (but not including) the last day of such Interest Period at the interest rate determined by the Administrative Agent as applicable to such Eurodollar Advance based upon Unit's selections under Sections 2.9 and 2.10 and otherwise in accordance with the terms hereof. No Interest Period may end after the Facility Termination Date.

2.12. Rates Applicable After Default. Notwithstanding anything to the contrary contained in Section 2.9, 2.10 or 2.11, during the continuance of a Default the Required Lenders may, at their option, by written notice to Unit, declare that no Advance may be made as, converted into or continued as a Eurodollar Advance. During the continuance of a Default the Required Lenders may, at their option, by written notice to Unit, declare that (i) each Eurodollar Advance will bear interest for the remainder of the applicable Interest Period at the rate otherwise applicable to such Interest Period plus an additional 2% per annum, (ii) each Floating Rate Advance will bear interest at a rate per annum equal to the Floating Rate in effect from time to time plus an additional 2% per annum and (iii) the LC Fee will be increased by an additional 2% per annum, provided that, during the continuance of a Default under Section 10.6 or 10.7, the interest rates set forth in clauses (i) and (ii) above and the increase in the LC Fee set forth in clause (iii) above will be applicable to all Credit Extensions without any election, notice or other action on the part of the Administrative Agent or any Lender.

2.13. Method of Payment.

2.13.1. All payments of the Obligations hereunder will be made, without setoff, deduction, or counterclaim, in immediately available funds to the Administrative Agent at the Administrative Agent's address specified pursuant to Section 15.1, or at any other banking address of the Administrative Agent specified in writing by the Administrative Agent to Unit, by 12:00 noon (local Tulsa time) on the date when due and will (except in the case of Reimbursement Obligations for which the LC Issuer has not been fully indemnified by the Lenders, or as otherwise specifically required hereunder) be applied ratably by the Administrative Agent among the Lenders. Each payment delivered to the Administrative Agent for the account of any Lender will be delivered promptly by the Administrative Agent to such Lender in the same type of funds that the Administrative Agent received at its address specified pursuant to Section 15.1 or at any banking address specified in a notice received by the Administrative Agent from such Lender. The

Administrative Agent is hereby authorized to charge the account of the Borrowers (other than any Excluded Account) maintained with BOk for each payment of principal, interest, Reimbursement Obligations and fees as it becomes due hereunder. Each reference to the Administrative Agent in this Section 2.13 will also be deemed to refer, and will apply equally, to the LC Issuer, in the case of payments required to be made by the Borrowers to the LC Issuer pursuant to Section 2.19.

2.13.2. When Administrative Agent collects or receives proceeds of Collateral, Administrative Agent will distribute all money so collected or received, and Administrative Agent and each Lender will apply all such money so distributed, as follows:

(a) first, for the payment of all Secured Obligations which are then due and if such money is insufficient to pay all such Secured Obligations, first to any reimbursements due Administrative Agent under Section 12.6 and then to the partial payment of all other Secured Obligations then due in proportion to the amounts thereof, or as Administrative Agent and Lender will otherwise agree;

(b) then for the prepayment of the Secured Obligations;

(c) last, for the payment or prepayment of any other indebtedness or obligations secured by the Collateral.

All payments applied to principal or interest on any Note will be applied first to any interest then due and payable, then to principal then due and payable, and last to any prepayment of principal and interest in compliance with Section 2.8. All distributions of amounts described in any of subsections (b) or (c) above will be made by Administrative Agent pro rata to each Lender then owed Secured Obligations described in such subsection in proportion to all amounts owed to Administrative Agent and all Lenders which are described in such subsection; provided that if any Lender then owes payments to LC Issuer for the purchase of a participation under Section 2.19.5 or to Administrative Agent under Section 13.7, any amounts otherwise distributable under this section to such Lender will be deemed to belong to LC Issuer, or Administrative Agent, respectively, to the extent of such unpaid payments, and Administrative Agent will apply such amounts to make such unpaid payments rather than distribute such amounts to such Lender.

2.14. Evidence of Indebtedness.

(i) Each Lender will maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrowers to such Lender resulting from each Loan made by such Lender from time to time, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(ii) The Administrative Agent will also maintain accounts in which it will record (a) the amount of each Loan made hereunder, the type thereof and the Interest Period with respect thereto, (b) the amount of any principal or interest due

and payable or to become due and payable from the Borrowers to each Lender hereunder, (c) the original stated amount of each LC and the amount of LC Obligations outstanding at any time, and (d) the amount of any sum received by the Administrative Agent hereunder from the Borrowers and each Lender's share thereof.

(iii) The entries maintained in the accounts maintained pursuant to paragraphs (i) and (ii) above will be prima facie evidence of the existence and amounts of the Obligations therein recorded; provided, however, that the failure of the Administrative Agent or any Lender to maintain such accounts or any error therein will not in any manner affect the obligation of the Borrowers to repay the Obligations in accordance with their terms.

(iv) Each Lender's Loans and interest therein will at all times be evidenced by a promissory note in the form of Exhibit A hereto (each a "Note") payable to the order of such Lender.

2.15. Telephonic Notices. The Borrowers hereby authorize the Lenders and the Administrative Agent to extend, convert or continue Advances, effect selections of types of Advances and to transfer funds based on telephonic notices made by any person or persons the Administrative Agent or any Lender in good faith believes to be acting on behalf of the Borrowers, it being understood that the foregoing authorization is specifically intended to allow Borrowing Notices and Conversion/Continuation Notices to be given telephonically. Unit agrees to deliver promptly to the Administrative Agent a written confirmation, if such confirmation is requested by the Administrative Agent or any Lender, of each telephonic notice signed by an Authorized Officer. If the written confirmation differs in any material respect from the action taken by the Administrative Agent and the Lenders, the records of the Administrative Agent and the Lenders will govern absent manifest error.

2.16. Interest Payment Dates. Interest accrued on each Floating Rate Advance will be payable on each monthly Payment Date, commencing with the first such date to occur after the date hereof, on any date on which the Floating Rate Advance is prepaid, whether due to acceleration or otherwise, and at maturity. Interest accrued on that portion of the outstanding principal amount of any Floating Rate Advance converted into a Eurodollar Advance on a day other than a Payment Date will be payable on the date of conversion. Interest accrued on each one month (30 day), two months (60 days) or three months (90 days) Interest Period for Eurodollar Advance will be payable on the last day of its applicable Interest Period, on any date on which the Eurodollar Advance is prepaid, whether by acceleration or otherwise, and at maturity. Interest accrued on each Eurodollar Advance having an Interest Period longer than three months (i.e., six months (180 days) Interest Period) will also be payable on the last day of each three-month interval during such Interest Period. Interest will be payable for the day an Advance is made but not for the day of any payment on the amount paid if payment is received prior to noon (local time) at the place of payment. If any payment of principal of or interest on an Advance will become due on a day which is not a Business Day, such payment will be made on the next succeeding Business Day and, in the case of a principal payment, such extension of time will be included in computing interest in connection with such payment.

2.17. Notification of Advances, Interest Rates, and LC Requests. Promptly after receipt thereof, the Administrative Agent will notify each Lender of the contents of each Borrowing Notice, Conversion/Continuation Notice, and repayment notice received by it hereunder. Promptly after notice from the LC Issuer, the Administrative Agent will notify each Lender of the contents of each request for issuance of a LC thereunder.

2.18. Non-Receipt of Funds by the Administrative Agent. Unless Unit or a

Lender, as the case may be, notifies the Administrative Agent prior to the date on which it is scheduled to make payment to the Administrative Agent of (i) in the case of a Lender, the proceeds of a Loan or (ii) in the case of the Borrowers, a payment of principal, interest or fees to the Administrative Agent for the account of the Lenders, that it does not intend to make such payment, the Administrative Agent may assume that such payment has been made. The Administrative Agent may, but will not be obligated to, make the amount of such payment available to the intended recipient in reliance upon such assumption. If such Lender or the Borrowers, as the case may be, have not in fact made such payment to the Administrative Agent, the recipient of such payment will, on demand by the Administrative Agent, repay to the Administrative Agent the amount so made available together with interest thereon in respect of each day during the period commencing on the date such amount was so made available by the Administrative Agent until the date the Administrative Agent recovers such amount at a rate per annum equal to (x) in the case of payment by a Lender, the Federal Funds Effective Rate for such day for the first three days and, thereafter, the interest rate applicable to the relevant Loan or (y) in the case of payment by the Borrowers, the interest rate applicable to the relevant Loan.

2.19. Letters of Credit.

2.19.1. Issuance. The LC Issuer hereby agrees, on the terms and conditions set forth in this Agreement, to issue standby Letters of Credit (each, a "LC") and to renew, extend, increase, decrease or otherwise modify each LC ("Modify," and each such action a "Modification"), from time to time from and including the date of this Agreement and prior to the Facility Termination Date upon the request of the Borrowers; provided that immediately after each such LC is issued or Modified, (i) the aggregate amount of the outstanding LC Obligations will not exceed $15,000,000.00 at any time and (ii) the Aggregate Outstanding Credit Exposure will not exceed the Aggregate Commitment. No LC will have an expiry date later than one year after the issuance thereof; provided that if such expiry date is after the fifth Business Day prior to the Facility Termination Date, Borrowers will deposit with the Administrative Agent on such date immediately available funds in an amount equal to or greater than the undrawn amount of such LC.

2.19.2. Participations. Upon the issuance or Modification by the LC Issuer of a LC in accordance with this Section 2.19, the LC Issuer will be deemed, without further action by any party hereto, to have unconditionally and irrevocably sold to each Lender, and each Lender will be deemed, without further action by any party hereto, to have unconditionally and irrevocably purchased from the LC Issuer, a participation in such LC (and each Modification thereof) and the related LC Obligations in proportion to its Pro Rata Share.

2.19.3. Notice. Subject to Section 2.19.1, Unit will give the LC Issuer notice prior to 10:00 a.m. (Tulsa time) at least one Business Day prior to the proposed date of issuance or Modification of each LC, specifying the beneficiary, the proposed date of issuance (or Modification) and the expiry date of such LC, and describing the proposed terms of such LC and the nature of the transactions proposed to be supported thereby. Upon receipt of such notice, the LC Issuer will promptly notify the Administrative Agent, and the Administrative Agent will promptly notify each Lender, of the contents thereof and of the amount of such Lender's participation in such proposed LC. The issuance or Modification by the LC Issuer of any LC will, in addition to the conditions precedent set forth in Article IV (the satisfaction of which the LC Issuer will have no duty to ascertain), be subject to the conditions precedent that such LC will be satisfactory to the LC Issuer and that the Borrowers will have executed and delivered such LC Application agreement and/or such other instruments and agreements relating to such LC as the LC Issuer will have reasonably requested (each, a "LC Application"). In the event of any conflict between the terms of this Agreement and the terms of any LC Application, the terms of this Agreement will control.

2.19.4. LC Fees. The Borrowers will pay to the Administrative Agent, for the account of the Lenders ratably in accordance with their respective Pro Rata Shares, at the time of issuance of each LC, a letter of credit fee calculated at an amount equal to the greater of $340.00 or a per annum rate equal to the Applicable Margin for Eurodollar Loans on the stated amount of such LC (each such fee described in this sentence an "LC Fee"). The Borrowers will also pay to the LC Issuer for its own account at the time of issuance of each LC, a fronting fee in an amount equal to 0.125% per annum of the initial stated amount, and documentary and processing charges in connection with the issuance or Modification of and draws under LCs in

accordance with the LC Issuer's standard schedule for such charges as in effect from time to time.

2.19.5. Administration; Reimbursement by Lenders. Upon receipt from the beneficiary of any LC of any demand for payment under such LC, the LC Issuer will notify the Administrative Agent and the Administrative Agent will promptly notify the Borrowers and each other Lender as to the amount to be paid by the LC Issuer as a result of such demand and the proposed payment date (the "LC Payment Date"). The responsibility of the LC Issuer to the Borrowers and each Lender will be only to determine that the documents (including each demand for payment) delivered under each LC in connection with such presentment will be in conformity in all material respects with such LC. In the absence of any gross negligence or willful misconduct by the LC Issuer, each Lender will be unconditionally and irrevocably liable without regard to the occurrence of any Default or any condition precedent whatsoever, to reimburse the LC Issuer on demand for (i) such Lender's Pro Rata Share of the amount of each payment made by the LC Issuer under each LC to the extent such amount is not reimbursed by the Borrowers pursuant to Section 2.19.6 below, plus (ii) interest on the foregoing amount to be reimbursed by such Lender, for each day from the date of the LC Issuer's demand for such reimbursement (or, if such demand is made after 11:00 a.m. (Tulsa time) on such date, from the next succeeding Business Day) to the date on which such Lender pays the

amount to be reimbursed by it, at a rate of interest per annum equal to the Federal Funds Effective Rate for the first three days and, thereafter, at a rate of interest equal to the rate applicable to Floating Rate Advances.

2.19.6. Reimbursement by Borrowers. The Borrowers will be irrevocably and unconditionally obligated to reimburse the LC Issuer on or before the applicable LC Payment Date for any amounts to be paid by the LC Issuer upon any drawing under any LC, without presentment, demand, protest or other formalities of any kind; provided that neither the Borrowers nor any Lender will hereby be precluded from asserting any claim for direct (but not consequential) damages suffered by the Borrowers or such Lender to the extent, but only to the extent, caused by (i) the willful misconduct or gross negligence of the LC Issuer in determining whether a request presented under any LC issued by it complied with the terms of such LC or (ii) the LC Issuer's failure to pay under any LC issued by it after the presentation to it of a request strictly complying with the terms and conditions of such LC. All such amounts paid by the LC Issuer and remaining unpaid by the Borrowers will bear interest, payable on demand, for each day until paid at a rate per annum equal to (x) the rate applicable to Floating Rate Advances for such day if such day falls on or before the applicable LC Payment Date and (y) the sum of 2% plus the rate applicable to Floating Rate Advances for such day if such day falls after such LC Payment Date. The LC Issuer will pay to each Lender ratably in accordance with its Pro Rata Share all amounts received by it from the Borrowers for application in payment, in whole or in part, of the Reimbursement Obligation in respect of any LC issued by the LC Issuer, but only to the extent such Lender has made payment to the LC Issuer in respect of such LC pursuant to Section 2.19.5. Subject to the terms and conditions of this Agreement, the Borrowers may request an Advance hereunder for the purpose of satisfying any Reimbursement Obligation.

2.19.7. Obligations Absolute. The Borrowers' obligations under this Section 2.19 will be absolute and unconditional under any and all circumstances and irrespective of any setoff, counterclaim or defense to payment which the Borrowers may have or have had against the LC Issuer, any Lender or any beneficiary of a LC. The Borrowers further agree with the LC Issuer and the Lenders that the LC Issuer and the Lenders will not be responsible for, and the Borrowers' Reimbursement Obligation in respect of any LC will not be affected by, among other things, the validity or genuineness of documents or of any endorsements thereon, even if such documents should in fact prove to be in any or all respects invalid, fraudulent or forged, or any dispute between or among the Borrowers, any of their Affiliates, the beneficiary of any LC or any financing institution or other party to whom any LC may be transferred or any claims or defenses whatsoever of the Borrowers or of any of their Affiliates against the beneficiary of any LC or any such transferee. The LC Issuer will not be liable for any error, omission, interruption or delay in transmission, dispatch or delivery of any message or advice, however transmitted, in connection with any LC. The Borrowers agree that any action taken or omitted by the LC Issuer or any Lender under or in connection with each LC and the related drafts and documents, if done without gross negligence or

willful misconduct, will be binding upon the Borrowers and will not put the LC Issuer or any Lender under any liability to the Borrowers. Nothing in this Section 2.19.7 is intended to limit the right of the Borrowers

to make a claim against the LC Issuer for damages as contemplated by the proviso to the first sentence of Section 2.19.6.

2.19.8. Actions of LC Issuer. The LC Issuer will be entitled to rely, and will be fully protected in relying, upon any LC, draft, writing, resolution, notice, consent, certificate, affidavit, letter, cablegram, telegram, telecopy, telex or teletype message, statement, order or other document believed by it to be genuine and correct and to have been signed, sent or made by the proper Person or Persons, and upon advice and statements of legal counsel, independent accountants and other experts selected by the LC Issuer. The LC Issuer will be fully justified in failing or refusing to take any action under this Agreement unless it will first have received such advice or concurrence of the Required Lenders as it reasonably deems appropriate or it will first be indemnified to its reasonable satisfaction by the Lenders against any and all liability and expense which may be incurred by it by reason of taking or continuing to take any such action. Notwithstanding any other provision of this Section 2.19, the LC Issuer will in all cases be fully protected in acting, or in refraining from acting, under this Agreement in accordance with a request of the Required Lenders, and such request and any action taken or failure to act pursuant thereto will be binding upon the Lenders and any future holders of a participation in any LC.

2.19.9. Indemnification. The Borrowers will indemnify and hold harmless each Lender, the LC Issuer and the Administrative Agent, and their respective directors, officers, Administrative Agents and employees from and against any and all claims and damages, losses, liabilities, costs or expenses which such Lender, the LC Issuer or the Administrative Agent may incur (or which may be claimed against such Lender, the LC Issuer or the Administrative Agent by any Person whatsoever) by reason of or in connection with the issuance, execution and delivery or transfer of or payment or failure to pay under any LC or any actual or proposed use of any LC, including, without limitation, any claims, damages, losses, liabilities, costs or expenses which the LC Issuer may incur by reason of or in connection with (i) the failure of any other Lender to fulfill or comply with its obligations to the LC Issuer hereunder (but nothing herein contained will affect any rights the Borrowers may have against any defaulting Lender) or (ii) by reason of or on account of the LC Issuer issuing any LC which specifies that the term "Beneficiary" included therein includes any successor by operation of law of the named Beneficiary, but which LC does not require that any drawing by any such successor Beneficiary be accompanied by a copy of a legal document, satisfactory to the LC Issuer, evidencing the appointment of such successor Beneficiary; provided that the Borrowers will not be required to indemnify any Lender, the LC Issuer or the Administrative Agent for any claims, damages, losses, liabilities, costs or expenses to the extent, but only to the extent, caused by (x) the willful misconduct or gross negligence of the LC Issuer in determining whether a request presented under any LC complied with the terms of such LC or (y) the LC Issuer's failure to pay under any LC after the presentation to it of a request strictly complying with the terms and conditions of such LC. Nothing in this Section 2.19.9 is intended to limit the obligations of the Borrowers under any other provision of this Agreement.

2.19.10. Lenders' Indemnification. Each Lender will, ratably in accordance with its Pro Rata Share, indemnify the LC Issuer, its Affiliates and their respective directors, officers, Administrative Agents and employees (to the extent not reimbursed by the Borrowers) against any cost, expense (including reasonable counsel fees and disbursements), claim, demand, action, loss or liability (except such as result from such indemnitees' gross negligence or willful misconduct or the LC Issuer's failure to pay under any LC after the presentation to it of a request strictly complying with the terms and conditions of the LC) that such indemnitees may suffer or incur in connection with this Section 2.19 or any action taken or omitted by such indemnitees hereunder.

2.20. Additional Agency Fees. Borrowers will pay certain additional fees to the Administrative Agent and the Syndication Agent in the amounts and on the terms described in the Agent Fee Letter.

2.21 Loan Purposes Advances may be requested by Unit on behalf of the Borrowers for (i) payment in full of any Existing Indebtedness and extinguishment of the commitments of the Existing Lenders, (ii) funds necessary for the consummation of the PetroCorp acquisition, (iii) general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties and (b) contract drilling services, (iv) issuance of LCs, and (v) general corporate purposes of the Borrowers.

ARTICLE III

YIELD PROTECTION; TAXES

3.1. Yield Protection. If, on or after the date of this Agreement, the adoption of any law or any governmental or quasi-governmental rule, regulation, policy, guideline or directive (whether or not having the force of law), or any change in the interpretation or administration thereof by any governmental or quasi-governmental authority, central bank or comparable agency charged with the interpretation or administration thereof, or compliance by any Lender or applicable banking address or the LC Issuer with any request or directive (whether or not having the force of law) of any such authority, central bank or comparable agency:

(i) subjects any Lender or the LC Issuer to any Taxes, or changes the basis of taxation of payments (other than Excluded Taxes) to any Lender or the LC Issuer regarding its Eurodollar Loans or participations in Eurodollar Advances, or

(ii) imposes or increases or deems applicable any reserve, assessment, insurance charge, special deposit or similar requirement against assets of, deposits with or for the account of, or credit extended by, any Lender or the LC Issuer (other than reserves and assessments taken into account in determining the interest rate applicable to Eurodollar Advances), or

(iii) imposes any other condition the result of which is to increase the cost to any Lender, the interbank eurocurrency deposit market or the LC Issuer of

making, funding or maintaining its Eurodollar Loans, or of issuing or participating in LCs, or reduces any amount receivable by any Lender, the interbank eurocurrency deposit market or the LC Issuer in connection with its Eurodollar Loans, LCs or participations therein, or requires any Lender, the interbank eurocurrency deposit market or the LC Issuer to make any payment calculated by reference to the amount of Eurodollar Loans, LCs or participations therein held or interest or LC Fees received by it, by an amount deemed material by such Lender or the LC Issuer as the case may be and the result of any of the foregoing is to increase the cost to such Lender or the LC Issuer, as the case may be, of making or maintaining its Eurodollar Loans or Commitment or of issuing or participating in LCs or to reduce the return received by such Lender, the interbank eurocurrency deposit market or the LC Issuer, as the case may be, in connection with such Eurodollar Loans, Commitment, LCs or participations therein,

then, within 15 days of demand by the Administrative Agent or the LC Issuer, as the case may be, the Borrowers will pay the Administrative Agent for the account of such Lender or the LC Issuer, as the case may be, such additional amount or amounts as will compensate such Lender or the LC Issuer, as the case may be, for such increased cost or reduction in amount received.

3.2. Changes in Capital Adequacy Regulations. If a Lender or the LC Issuer determines, in good faith, the amount of capital required or expected to be maintained by such Lender or the LC Issuer, or the LC Issuer, or any corporation controlling such Lender or the LC Issuer is increased as a result of a Change, then, within 15 days of demand by such Lender or the LC Issuer, the Borrowers will pay such Lender or the LC Issuer the amount necessary to compensate for any shortfall in the rate of return on the portion of such increased capital which such Lender or the LC Issuer determined is attributable to this Agreement, its Outstanding Credit Exposure or its Commitment to make Loans and issue or participate in LCs, as the case may be, hereunder (after taking into account such Lender's or the LC Issuer's policies as to capital adequacy). "Change" means (i) any change after the date of this Agreement in the Risk-Based Capital Guidelines or (ii) any adoption of or change in any other law, governmental or quasigovernmental rule, regulation, policy, guideline, interpretation, or

directive (whether or not having the force of law) after the date of this Agreement which affects the amount of capital required or expected to be maintained by any Lender or the LC Issuer or any corporation controlling any Lender or the LC Issuer. "Risk-Based Capital Guidelines" means (i) the riskbased capital guidelines in effect in the United States on the date of this Agreement, including transition rules, and (ii) the corresponding capital regulations promulgated by regulatory authorities outside the United States implementing the July 1988 report of the Basle Committee on Banking Regulation and Supervisory Practices Entitled "International Convergence of Capital Measurements and Capital Standards," including transition rules, and any amendments to such regulations adopted prior to the date of this Agreement.

3.3. Taxes.

(i) All payments by the Borrowers to or for the account of any Lender, the LC Issuer or the Administrative Agent hereunder or under any Note or LC Application will be made free and clear of and without deduction for any

and all Taxes. If the Borrowers are required by law to deduct any Taxes from any payment to a Lender, the LC Issuer or the Administrative Agent, to the extent not prohibited by applicable law, (a) the payment will be increased so that after making all required deductions (including deductions applicable to payments under this Section 3.3) such Lender, the LC Issuer or the Administrative Agent (as the case may be) receives an amount equal to the payment it would have received had no deductions been made, (b) the Borrowers will make such deductions, (c) the Borrowers will pay the full amount deducted to the relevant authority in accordance with applicable law and (d) the Borrowers will furnish to the Administrative Agent a copy of a receipt evidencing payment within 30 days after the payment is made.

(ii) In addition, the Borrowers hereby agree to pay any present or future stamp or documentary taxes and any other excise or property taxes, charges or similar levies which arise from any payment made under this Agreement or under any Note or LC Application or from the execution or delivery of, or otherwise with respect to, this Agreement or any Note or LC Application ("Other Taxes").

(iii) The Borrowers hereby agree to indemnify the Administrative Agent, the LC Issuer and each Lender for the full amount of Taxes or Other Taxes (including, without limitation, any Taxes or Other Taxes imposed on payments under this Section 3.3) paid by the Administrative Agent, the LC Issuer or such Lender and any liability (including penalties, interest and expenses) arising therefrom or with respect thereto. Payments properly due under this indemnification will be made within 30 days following the date the Administrative Agent, the LC Issuer or such Lender requests payment.

(iv) If the U.S. Internal Revenue Service or any other governmental authority of the United States or any other country or any political subdivision thereof asserts a claim that the Agent did not properly withhold tax from payments to or for the account of any Lender (because the appropriate form was not delivered or properly completed, because such Lender failed to notify the Agent of a change in circumstances which rendered its exemption from withholding ineffective, or for any other reason), such Lender will indemnify the Agent fully for all amounts paid, directly or indirectly, by the Agent as tax, withholding therefor, or otherwise, including penalties and interest, and including taxes imposed by any jurisdiction on amounts payable to the Agent under this subsection, together with all costs and expenses related thereto (including attorneys fees and time charges of attorneys for the Agent, which attorneys may be employees of the Agent). The obligations of the Lenders under this Section 3.3(iv) will survive the payment of the Obligations and termination of this Agreement. Any liability under this subsection (iv) will not be a liability of the Borrowers

3.4. Availability of Eurodollar Advances. If any Lender determines that maintenance

of its Eurodollar Loans at a suitable banking location would violate any applicable law, rule, regulation, or directive, whether or not having the force

of law, or if the Required Lenders determine that (i) deposits of a type and maturity appropriate to match fund Eurodollar Advances are not available or (ii) the interest rate applicable to Eurodollar Advances does not accurately reflect the cost of making or maintaining Eurodollar Advances, then the Administrative Agent will suspend the availability of Eurodollar Advances and require any affected Eurodollar Advances to be repaid or converted to Floating Rate Advances, subject to the payment of any funding indemnification amounts required by Section 3.5.

3.5. Funding Indemnification. If any payment of a Eurodollar Advance occurs on a date which is not the last day of the applicable Interest Period, whether because of acceleration, prepayment or otherwise, or a Eurodollar Advance is not made on the date specified by the Borrowers for any reason other than default by the Lenders, the Borrowers will indemnify each Lender for any resulting loss or cost incurred by it.

ARTICLE IV

CONDITIONS PRECEDENT

4.1. Initial Credit Extension. The Lenders will not be required to make the initial Credit Extension hereunder unless:

4.1.1. Unit has furnished to the Administrative Agent at its main banking offices in Tulsa, Oklahoma, each of the following, duly executed and delivered in form, substance and date satisfactory to the Administrative Agent, with sufficient copies for all of the Lenders:

(i) Copies of the certificate of incorporation of each of the Credit Parties, together with all amendments, and a certificate of good standing, each certified by the appropriate governmental officer in their respective jurisdiction of incorporation.

(ii) Copies, certified by the Secretary or Assistant Secretary of the Credit Parties, of their respective by-laws and of their respective Board of Directors' resolutions and of resolutions or actions of any other body authorizing the execution of the Loan Documents to which each Borrower is a party.

(iii) An incumbency certificate, executed by the Secretary or Assistant Secretary of the Credit Parties, which will identify by name and title and bear the signatures of the Authorized Officers and any other officers of the Borrower authorized to sign the Loan Documents to which such Borrower is a party, with the Administrative Agent and the Lenders being entitled to rely on such certificate until informed of any change in writing by such Borrower.

(iv) A certificate, signed by the chief financial officer of Unit (on behalf of all of the Credit Parties), stating that on the initial Credit Extension Date

no Default has occurred and is continuing, that all representations and warranties in the Loan Documents are true and correct and that no Material Adverse Effect has occurred.

(v) A written closing opinion of outside counsel to the Borrowers, addressed to the Administrative Agent and the Lenders in form, scope and substance satisfactory to the Administrative Agent.

(vi) This Agreement and a Note payable to the order of each Lender and, upon consummation of the merger contemplated by the PetroCorp Agreement, the Subsidiary Guaranty by PetroCorp, substantially in the form of Exhibit E of this Agreement.

(vii) Arrangements satisfactory to the Administrative Agent, the LC Issuer and any applicable beneficiary concerning replacement or cash collateralization of any existing PetroCorp unexpired letters of credit at the time of the consummation of the acquisition of PetroCorp by Unit, payment in full of any Indebtedness owing under the Existing Credit Agreement to the Existing Lenders, including all interest thereon and that any unexpired letters of credit issued thereunder have been terminated or otherwise collateralized to the satisfaction of the Administrative Agent and the LC Issuer under the Existing Credit Agreement, including evidence satisfactory to Unit and the Administrative Agent of the cancellation of the Commitments issued

under the Existing Credit Agreement, termination of the credit facilities established under the Existing Credit Agreement.

(viii) The Collateral Documents described in the Security Schedule.

(ix) A fully executed copy of the PetroCorp Agreements and evidence satisfactory to the Administrative Agent that the acquisition of PetroCorp has been consummated under the PetroCorp Agreement, including without limitation, that evidence that the existing credit facility of PetroCorp has been extinguished and fully paid and discharged and that any Liens filed against PetroCorp will be promptly discharged and released of record.

(x) Such other documents, certificates, instruments and information as any Lender or its counsel may have reasonably requested and satisfactory review by the Lenders of all environmental, litigation, insurance and other matters deemed appropriate by the Administrative Agent, including without limitation, summary title due diligence data concerning the Rigs and/or the oil and gas portion of the Borrowing Base Property (division orders, evidence of payment by the purchaser of production, etc.) as reasonably deemed necessary by the Administrative Agent or the Required Lenders.

(xi) All facility fees owed to the Lenders and all fees and expenses owing by Borrowers to Administrative Agent and the Syndication Agent will

have been paid, including the reasonable attorneys fees and expenses of legal counsel for the Administrative Agent that have been billed and submitted to the Agent as of the Closing Date.

4.2. Each Credit Extension. The Lenders will not be required to make any Credit Extension unless on the applicable Credit Extension Date:

(i) There exists no Default and the representations and warranties contained in Article V are then true and correct in all material respects as of such Credit Extension Date except to the extent a representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty will have been true and correct on and as of such earlier date.

(ii) All legal matters incident to the making of such Credit Extension will be satisfactory to the Administrative Agent.

(iii) No Material Adverse Effect will have occurred to, and no event or circumstance will have occurred that could reasonably be expected to cause a Material Adverse Effect to, Unit's consolidated financial condition or to the Credit Parties' businesses since the date of the financial statements most recently delivered pursuant to Sections 6.1 (i) and (ii) hereof.

(iv) The making of such Loan or the issuance of such Letter of Credit will not be prohibited by any Law and will not subject any Lender or any LC Issuer to any penalty or other adverse condition under any Law.

(v) Each Borrower and Subsidiary Guarantor will be solvent.

(vi) Administrative Agent will have received all documents and instruments which Administrative Agent has then reasonably requested, in addition to those described in Section 4.1, as to (i) the accuracy and validity of or compliance with all representations, warranties, and covenants made by any Borrower or Subsidiary Guarantor in this Agreement in all material respects and the other Loan Documents, and (ii) the satisfaction of all conditions contained in this Agreement.

Each Borrowing Notice or request for issuance of a LC will constitute a representation and warranty by the Borrowers that the conditions contained in Section 4.2 have been satisfied.

ARTICLE V

REPRESENTATIONS AND WARRANTIES

The Borrowers represent and warrant to the Lenders that:

5.1. Existence and Good Standing. Each Credit Party is a corporation, duly and

properly incorporated or organized, as the case may be, validly existing and (to the extent such concept applies to such entity) in good standing under the laws of its jurisdiction of incorporation or organization and has all requisite authority to carry on its business in each jurisdiction as now conducted.

5.2. Authorization and Validity. Each Credit Party has the power and authority and legal right to execute and deliver the Loan Documents to which it is a party and to perform its obligations thereunder. The execution and delivery by each Credit Party of the Loan Documents to which it is a party and the performance of its obligations thereunder have been duly authorized by proper corporate proceedings. The Loan Documents to which a Credit Party is a party constitute legal, valid and binding obligations of such Credit Party enforceable against such Credit Party in accordance with their terms, except as enforceability may be limited by bankruptcy, insolvency or similar laws affecting the enforcement of creditors' rights generally.

5.3. No Conflict; Government Consent. Neither the execution and delivery by any of the Credit Parties of the Loan Documents to which it is a party, nor the consummation of the transactions contemplated by the Loan Documents, nor compliance with the provisions of the Loan Documents will violate in any material respect (i) any law, rule, regulation, order, writ, judgment, injunction, decree or award binding on the Credit Parties or (ii) any of the Credit Parties' articles or certificate of incorporation, partnership agreement, certificate of partnership, articles or certificate of organization, by-laws, or operating or other management agreement, as the case may be, or (iii) the provisions of any indenture, instrument or agreement to which any of the Credit Parties is a party or is subject, or by which it, or its Property, is bound, or conflict with or constitute a default, or result in, or require, the creation or imposition of any Lien in, of or on the Property of the Credit Parties pursuant to the terms of any such indenture, instrument or agreement. No order, consent, adjudication, approval, license, authorization, or validation of, or filing, recording or registration with, or exemption by, or other action in respect of any governmental or public body or authority, or any subdivision thereof, which has not been obtained by the Credit Parties, is required to be obtained by the Credit Parties in connection with the execution and delivery of the Loan Documents, the borrowings under this Agreement, the payment and performance by the Credit Parties of the Obligations or the legality, validity, binding effect or enforceability of any of the Loan Documents.

5.4. Financial Statements. The audited annual and unaudited quarterly, consolidated financial statements of Unit and its consolidated Subsidiaries previously delivered to the Lenders were prepared in accordance with GAAP (except that the unaudited interim financial statements were subject to normal and recurring year-end adjustments) in effect on the date such statements were prepared and fairly present the consolidated financial condition and operations of the Credit Parties at such date and the consolidated results of their operations for the period then ended.

5.5. Material Adverse Change. Since September 30, 2003, there has been no change in the business, Property, prospects, condition (financial or otherwise) or results of operations of the Credit Parties which could reasonably be expected to have a Material Adverse Effect. There is no fact known to the Credit Parties which has a Material Adverse Effect or in the future is reasonably likely to have (so far as the Credit Parties can now foresee) a Material Adverse Effect and which has not been set forth in this Agreement or the other documents, certificates and

statements furnished to the Administrative Agent by or on behalf of the Credit Parties prior to, or on, the Closing Date in connection with the transactions contemplated by this Agreement.

5.6. Taxes. The Credit Parties have filed all United States federal tax returns and all other material tax returns which are required to be filed and have paid all taxes due pursuant to said returns or pursuant to any assessment received by the Credit Parties or any of their Subsidiaries, except such taxes, if any, that are being contested in good faith and as to which adequate reserves have been provided in accordance with GAAP and which no Lien has been filed or

perfected. No tax liens have been filed and no claims are being asserted with respect to any such taxes. The charges, accruals and reserves on the books of the Credit Parties and their Subsidiaries in respect of any taxes or other governmental charges are adequate.

5.7. Litigation and Contingent Obligations. There is no litigation, arbitration, governmental investigation, proceeding or inquiry pending or, to the knowledge of any of their officers, threatened against or affecting the Credit Parties which could reasonably be expected to have a Material Adverse Effect or which seeks to prevent, enjoin or delay the making of any Credit Extensions. Other than any liability incident to any litigation, arbitration or proceeding which could not reasonably be expected to have a Material Adverse Effect, the Credit Parties have no material Contingent Obligations not provided for or disclosed in the financial statements referred to in Section 5.4 except as set forth on Schedule 8 of this Agreement.

5.8. Subsidiaries. The Disclosure Schedule contains an accurate list of all Subsidiaries of Unit as of the date of this Agreement, setting forth their respective jurisdictions of organization and the percentage of their respective capital stock or other ownership interests owned by the Unit or the other Credit Parties. All of the issued and outstanding shares of capital stock or other ownership interests of the Subsidiaries have been (to the extent such concepts are relevant with respect to such ownership interests) duly authorized and issued and are fully paid and non-assessable.

5.9. ERISA. The Unfunded Liabilities of all Single Employer Plans do not in the aggregate exceed $500,000. Neither the Credit Parties nor any other member of the Controlled Group has incurred, or is reasonably expected to incur, any withdrawal liability to Multiemployer Plans. Each Plan complies in all material respects with all applicable requirements of law and regulations, no Reportable Event has occurred with respect to any Plan, neither the Credit Parties nor any other member of the Controlled Group has withdrawn from any Plan or initiated steps to do so, and no steps have been taken to reorganize or terminate any Plan except as disclosed in the Disclosure Schedule.

5.10. Accuracy of Information. No information, exhibit or report furnished by the Credit Parties to the Administrative Agent or to any Lender in connection with the negotiation of, or compliance with, the Loan Documents contained any material misstatement of fact or omitted to state a material fact or any fact necessary to make the statements contained therein not misleading.

5.11. Margin Stock No part of the Loan proceeds of any Advances hereunder will be used to purchase or carry any margin stock or to extend credit to others for the purpose of

purchasing or carrying any margin stock. If requested by the Administrative Agent or the Required Lenders, the Credit Parties will furnish to the Collateral Agent a statement in conformity with the requirements of Federal Reserve Form U-1, referred to in Regulation U, to the foregoing effect. No indebtedness being reduced or retired out of the proceeds of the Advances was or will be incurred for the purpose of purchasing or carrying any margin stock within the meaning of Regulation U or any "margin security" within the meaning of Regulation T. "Margin Stock" within the meaning of Regulation U does not constitute more than 25% of the value of the consolidated assets of Unit and its Subsidiaries.

5.12. Material Agreements. Unit has no actual knowledge of (i) any material agreement or material instrument to which any Borrower is a party or (ii) any charter or other corporate restriction, either of which (i) or (ii), under current conditions and circumstances known to Unit, constitutes or is reasonably expected to have a Material Adverse Effect. None of the Credit Parties is in default in the performance, observance or fulfillment of any of the obligations, covenants or conditions contained in (i) any agreement to which it is a party, which default could reasonably be expected to have a Material Adverse Effect or (ii) any agreement or instrument evidencing or governing Indebtedness, which default could reasonably be expected to have a Material Adverse Effect.

5.13. Compliance With Laws. The Credit Parties have complied with all applicable statutes, rules, regulations, orders and restrictions of any domestic or foreign government or any instrumentality or agency thereof having jurisdiction over the conduct of their respective businesses or the ownership of their respective Property except for any failure to comply with any of the foregoing which could not reasonably be expected to have a Material Adverse Effect.

5.14. Ownership of Properties. Unit and each of its Subsidiaries has marketable title to all of the properties and assets reflected as owned in the

consolidated financial statements of Unit, in each case free and clear of all Liens other than Permitted Encumbrances (including those created under the Loan Documents described and defined in the Existing Credit Agreement) and such as do not materially and adversely affect the value of the property and do not materially interfere with the use made or proposed to be made of such property by Unit or its Subsidiaries, which such total Liens do not exceed $1,000,000 in the aggregate. The real property, improvements, equipment and personal property held under lease by Unit or any Subsidiary of Unit are held under valid enforceable leases, with such exceptions as are not material and do not materially interfere with the use made or proposed to be made of such real property, improvements, equipment or personal property by Unit or any Subsidiary of Unit. Each of Credit Parties possesses all licenses, permits, franchises, patents, copyrights, trademarks and trade names, and other intellectual property (or otherwise possesses the right to use such intellectual property without violation of the rights of any other Person) which are necessary to carry out its business as presently conducted and as proposed to be conducted hereafter.

5.15. Plan Assets; Prohibited Transactions. Neither the execution of this Agreement nor the making of Loans hereunder gives rise to a prohibited transaction within the meaning of Section 406 of ERISA or Section 4975 of the Code. Since the effective date of Title IV of ERISA, no Reportable Event has occurred with respect to any Plan. The Credit Parties and their Guarantors have fulfilled all their obligations under the funding standards of ERISA and the

Code and are in compliance in all material respects with the applicable ERISA and Code provisions with respect to each Plan. Since the effective date of Title IV of ERISA there have not been any nor are there now existing any events or conditions that would permit any Plan to be terminated under circumstances which would cause the lien provided under Section 4068 of ERISA to attach to the assets of the Credit Parties or any of the Subsidiary Guarantors. No Borrower has (i) sought any waiver of the minimum funding standard under Section 412 of the Code, (ii) failed to make any contribution or payment to any Plan, or made any amendment to any Plan, which has resulted or could result in the imposition of a Lien or the posting of a bond or other security under ERISA or the Code, or (iii) incurred any liability under Title IV of ERISA.

5.16. Environmental Matters. Except as set forth on Schedule 5:

(a) To the best of the Credit Parties' knowledge and belief, the Properties owned, leased or operated by the Credit Parties do not contain, and have not previously contained, any materials of environmental concern in amounts or concentrations which (i) constitute or constituted a violation of, or (ii) could give rise to liability under, any Environmental Law except in either case insofar as such violation or liability, or any aggregation thereof, is not reasonably likely to result in a Material Adverse Effect.

(b) To the best of the Credit Parties' knowledge and belief, the Properties and all operations at the Properties are in compliance in all material respects, and have, for the lesser of the last five years or for the duration of their ownership, lease, or operation by the Credit Parties, been in compliance in all material respects with all applicable Environmental Laws, and there is no contamination at, under or about the Properties or violation of any Environmental Law with respect to the Properties or the business operated by the Credit Parties or any of their Subsidiaries (collectively, the "Business") which could interfere with the continued operation of the Properties or impair the fair saleable value thereof.

(c) None of the Credit Parties has received any notice of violation, alleged violation, non-compliance, liability or potential liability regarding environmental matters or compliance with Environmental Laws with regard to any of the Properties or the Business, nor do the Credit Parties have knowledge or reason to believe that any such notice will be received or is being threatened except insofar as such notice or threatened notice, or any aggregation thereof, does not involve a matter or matters that is or are reasonably likely to result in a Material Adverse Effect.

(d) To the best of the Credit Parties' knowledge and belief, materials of environmental concern have not been transported or disposed of from the Properties in violation of, or in a manner or to a location which could give rise to liability under, any Environmental Law, nor have any materials of environmental concern been generated, treated, stored or disposed of at, on or under any of the Properties in violation of, or in a manner that could give rise to liability under, any applicable Environmental Law except insofar as any such violation or liability referred to in this paragraph,

or any aggregation thereof, is not reasonably likely to result in a Material Adverse Effect.

(e) No judicial proceeding or governmental or administrative action is pending or, to the knowledge of the Borrower, threatened, under any Environmental Law to which the Credit Parties thereof are or will be named as a party with respect to the Properties or the Business, nor are there any consent decrees or other decrees, consent orders, administrative orders or other orders, or other administrative or judicial requirements outstanding under any Environmental Law with respect to the Properties or the Business except insofar as such proceeding, action, decree, order or other requirement, or any aggregation thereof, is not reasonably likely to result in a Material Adverse Effect.

(f) There has been no release or threat of release of materials of environmental concern at or from the Properties, or arising from or related to the operations of the Borrower in connection with the Properties or otherwise in connection with the Business, in violation of or in amounts or in a manner that could give rise to liability under Environmental Laws except insofar as any such violation or liability referred to in this paragraph, or any aggregation thereof, is not reasonably likely to result in a Material Adverse Effect.

5.17 Names and Places of Business. No Borrower has, during the preceding five years, had, been known by, or used any other trade or fictitious name. The chief executive office and principal place of business of each Credit Party are located at the address of the Credit Parties prescribed in Section 15.1.

5.18. Possession of Franchises, Licenses. The Credit Parties have in their possession, or has timely applied for, all franchises, certificates, licenses, permits and other authorizations from governmental political subdivisions or regulatory authorities, free from burdensome restrictions, that are necessary in any material respect for the ownership, maintenance and operation of their properties and assets, and none of the Credit Parties is in violation of any thereof in any material respect.

5.19. Rate Management Transactions. Except as forth on Schedule 6, as of the Closing Date, a true and complete list of all Rate Management Transactions (including commodity price swap agreements, forward agreements or contracts of sale which provide for prepayment for deferred shipment or delivery of oil, gas or other commodities) of the Credit Parties, listing the counterparties thereto.

ARTICLE VI

AFFIRMATIVE COVENANTS

During the term of this Agreement, unless the Required Lenders will otherwise consent in writing:

6.1. Reports. Unit will maintain and furnish to the Lenders:

(i) Within 80 days after the close of each of its fiscal years, the financial statements of Unit and its Subsidiaries, together with an unqualified audit report certified by Unit's independent certified public accountants, prepared in accordance with GAAP on a consolidated basis, including a balance sheet as of the end of such period and statements of operations, stockholders equity and cash flows for such period.

(ii) Within 45 days after the close of the first three quarterly periods of each of its fiscal years, consolidated unaudited balance sheets as at the close of each such period and statements of operations, stockholders equity and cash flows for the period from the beginning of such fiscal year to the end of such quarter, all certified by its chief financial officer.

(iii) Together with the financial statements required under Sections 6.1(i) and (ii), copies of all certifications made by officers of Unit to the SEC in connection with such financial statements and a compliance certificate in substantially the form of Exhibit B signed by Unit's chief financial officer showing the calculations necessary to determine compliance with this Agreement and

stating that no Default exists, or if any Default exists, stating the nature and status of such Default.

(iv) As soon as practicable and in any event within 10 days after the Credit Parties know that any Reportable Event has occurred with respect to any Plan, a statement, signed by the chief financial officer of Unit, describing said Reportable Event and the action which the Credit Parties propose to take regarding the Reportable Event.

(v) As soon as practicable and in any event within 10 days after receipt by the Credit Parties, a copy of (a) any notice or claim to the effect that the Credit Parties is or may be liable to any Person as a result of the release by the Credit Parties, or any other Person of any toxic or hazardous waste or substance into the environment, and (b) any notice alleging any violation of any federal, state or local environmental, health or safety law or regulation by the Credit Parties, which, in either case, could reasonably be expected to have a Material Adverse Effect.

(vi) Promptly on the furnishing to the stockholders of the Unit, copies of all financial statements, reports and proxy statements so furnished.

(vii) By April 1 of each year (commencing as of April 1, 2004), an Engineering Report prepared as of the prior December 31, by petroleum engineers who are employees of Credit Parties and audited by Ryder Scott Company, or such other firm of independent petroleum engineers chosen by Unit and acceptable to the Administrative Agent, concerning all oil and gas properties and interests owned by any Credit Parties and their Subsidiaries which are located in or offshore of the United States and which have attributable to them proved oil or

gas reserves. This reserve audit described above will encompass a review of the reserves associated with oil and gas properties comprising at least 80% of the value stated in the report. The Engineering Report will be satisfactory to Administrative Agent, will contain sufficient information to enable Credit Parties to meet the reporting requirements concerning oil and gas reserves contained in Regulations S-K and S-X promulgated by the SEC, will take into account any "over/under produced" status under gas balancing arrangements, and will contain information and analysis comparable in scope to that contained in the Initial Engineering Report.

(viii) By October 1 of each year (commencing as of October 1, 2004), and promptly following notice of a Special Redetermination under Section 2.6.4, an Engineering Report prepared as of the preceding June 30 (or the last day of the prior calendar month in the case of an additional redetermination) by petroleum engineers who are employees of Borrowers, together with an accompanying report on property sales, property purchases and changes in categories, both in the same form and scope as the reports in (x) above.

(ix) By April 1 and October 1 of each year, beginning April 1, 2004, a report describing the gross volume of production and sales attributable to production during the prior six-month period from the properties described in the Engineering Report in Section 6.1(vii) or Section 6.1(viii) and describing the related severance taxes, other taxes, and leasehold operating expenses attributable thereto and incurred during such month.

(x) Such other information (including non-financial information) as the Administrative Agent or any Lender may from time to time reasonably request.

6.2. Use of Proceeds. The Borrowers will use such proceeds of the Credit Extensions as necessary to refinance any Existing Indebtedness with the Existing Lenders, to fund the consummation of the PetroCorp acquisition, for general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, and (b) contract drilling services, the issuance of LCs and for general corporate purposes. The Borrower will not, nor will they permit any Subsidiary to, use any of the proceeds of the Advances to purchase or carry any "margin stock" (as defined in Regulations T and U).

6.3. Notice of Default. Unit will give prompt notice in writing to the Lenders of the occurrence of any Default and of any other development, financial or otherwise, which could reasonably be expected to have a Material Adverse

Effect.

6.4. Conduct of Business. The Credit Parties will each carry on and conduct its business in substantially the same manner and in substantially the same fields of enterprise as it is presently conducted and do all things necessary to remain duly incorporated or organized, validly existing and (to the extent such concept applies to such entity) in good standing as a domestic corporation, partnership or limited liability company in its jurisdiction of incorporation

or organization, as the case may be, and maintain all requisite authority to conduct its business in each jurisdiction in which its business is conducted.

6.5. Taxes. The Credit Parties will timely file complete and correct United States federal and applicable foreign, state and local tax returns required by law and pay when due all taxes, assessments and governmental charges and levies upon it or its income, profits or Property, except those which are being contested in good faith by appropriate proceedings and with respect to which adequate reserves have been provided in accordance with GAAP.

6.6. Insurance. The Credit Parties will maintain with, to the best of Unit's knowledge and belief, financially sound and reputable insurance companies insurance on all their Property in such amounts and covering such risks as is consistent with their prior business practice and deemed prudent by industry standards, and the Credit Parties will furnish to any Lender upon request full information as to the insurance carried.

6.7. Compliance With Laws. The Credit Parties will comply, in all material respects, with all laws, rules, regulations, orders, writs, judgments, injunctions, decrees or awards to which it may be subject including, without limitation, all Environmental Laws.

6.8. Maintenance of Properties. The Credit Parties will do all things reasonably necessary to maintain, preserve, protect and keep their respective Property in good repair, working order and condition, and make all necessary and proper repairs, renewals and replacements so that its business carried on in connection therewith may be conducted at all times consistent with such Credit Party's prior business practices.

6.9. Inspection. The Credit Parties will permit the Administrative Agent and the Lenders, by their respective representatives and Administrative Agents, to inspect any of the Property, books and financial records of the Credit Parties and each Subsidiary of any thereof, to examine and make copies of the books of accounts and other financial records of the Credit Parties and each Subsidiary of any thereof, and to discuss the affairs, finances and accounts of the Credit Parties and each Subsidiary with, and to be advised as to the same by, their respective officers at such reasonable times and intervals as the Administrative Agent or any Lender may designate.

6.10. Collateral Documents. Unit Drilling Company will execute and, where applicable, Borrowers will cause their respective Subsidiaries to execute and deliver (and, where applicable, acknowledge and have properly notarized) all of the Collateral Documents listed on Schedule 4 (Security Schedule) annexed hereto, each on the number of executed counterparts as deemed necessary or appropriate by the Administrative Agent and otherwise in form, scope and substance satisfactory to the Administrative Agent and its legal counsel.

6.11. Deposit Accounts/Setoff.

(a) Bank Accounts; Offset. To secure the repayment of the Obligations and the Rate Management Obligations, each Borrower grants to the Administrative Agent and each Lender a security interest, a lien, and a right of setoff and offset, each of which will

be in addition to all other interests, liens, and rights of any Lender at common Law, under the Loan Documents, or otherwise, and each of which will be upon and against (a) any and all moneys, securities and other property (and the proceeds therefrom) of such Borrower now or hereafter held or received by or in transit to any Lender from or for the account of such Borrower, whether for safekeeping, custody, pledge, transmission, collection or otherwise, (b) any and all deposits and deposit accounts (general or special, time or demand, provisional or final) of such Borrower with any Lender, and (c) any other credits and claims of such Borrower at any time existing against any Lender, including claims under certificates

of deposit (excluding from the foregoing security interest grant and right of set off and offset the accounts of the accounts at BOK as specified on Schedule 7 hereto (collectively, the "Excluded Accounts"). At any time and from time to time during the continuance of any Event of Default, each Lender is hereby authorized to foreclose upon, or to offset against the Obligations then due and payable (in either case without notice to any Borrower), any and all items hereinabove referred to. The remedies of foreclosure and offset are separate and cumulative, and either may be exercised independently of the other without regard to procedures or restrictions applicable to the other. ANY AND ALL RIGHTS TO REQUIRE THE ADMINISTRATIVE AGENT OR THE LENDERS TO EXERCISE ANY RIGHTS OR REMEDIES WITH RESPECT TO ANY OTHER COLLATERAL WHICH SECURES THE ADVANCES PRIOR TO EXERCISING ANY RIGHT OF SET OFF WITH RESPECT TO ANY DEPOSITS, CREDITS OR OTHER PROPERTY OF THE CREDIT PARTIES ARE HEREBY KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVED

(b) Control of Collateral. Administrative Agent hereby appoints each of the other Lenders to serve as its bailee to perfect Administrative Agent's Liens in any Collateral in the possession of any such other Lenders. Each Lender possessing any Collateral agrees to so act as bailee for Administrative Agent in accordance with the terms and provisions hereof. In furtherance of the foregoing, each Lender acknowledges that certain of the Credit Parties maintain deposit or other accounts (all such accounts maintained by any Credit Party with a Lender (other than the Excluded Accounts) are collectively called the "Lender Accounts" and individually called a "Lender Account") at one or more of the Lenders as disclosed pursuant to this Agreement. Each Lender agrees to hold its Lender Accounts as bailee for Administrative Agent to perfect the security interest held for the benefit of the Lenders therein. Prior to the receipt by a Lender of notice from Administrative Agent that it is exercising exclusive control over any Lender Account (a "Notice of Exclusive Control"), the Credit Parties are entitled to make withdrawals from the Lender Accounts and make deposits into and give entitlement orders with respect to the Lender Accounts. Once a Lender has a Notice of Exclusive Control, which such notice will not be given until a Default or Event of Default has occurred and is continuing, Administrative Agent will be the only party entitled to make withdrawals from or otherwise give any entitlement order or other direction with respect to the Lender Accounts. To the extent not already occurring, each Lender agrees to transfer, in immediately available funds by wire transfer to Administrative Agent, the amount of the collected funds credited to the deposit accounts which are Lender Accounts held by such Lender, and deliver to Administrative Agent all moneys or

instruments relating to such Lender Accounts or held therein and any other Collateral at any time Administrative Agent demands payment or delivery thereof after a Notice of Exclusive Control has been delivered to such Lender. Each Credit Party agrees that each Lender is authorized to immediately deliver all the Collateral to Administrative Agent upon the Lender's receipt of Notice of Exclusive Control from Administrative Agent. No Lender (other than Administrative Agent acting for the benefit of the other Lenders) will exercise any right of set-off or banker lien against any Lender Account; provided that a Lender will be entitled to charge, or set-off against a Lender Account and retain for its own account, any customary fees, costs, charges and expenses owed to it in connection with the opening, operating and maintaining such Lender Account and for the amount of any item credited to such Lender Account that is subsequently returned for any reason.

(c) Ratable Payments. If any Lender, whether by setoff or otherwise, has payment made to it upon its Outstanding Credit Exposure (other than payments received pursuant to Article III) in a greater proportion than that received by any other Lender, such Lender agrees, promptly upon demand, to purchase a portion of the Aggregate Outstanding Credit Exposure held by the other Lenders so that after such purchase each Lender will hold its Pro Rata Share of the Aggregate Outstanding Credit Exposure. If any Lender, whether in connection with setoff or amounts which might be subject to setoff or otherwise, receives collateral or other protection for its Obligations or such amounts which may be subject to setoff, such Lender agrees, promptly upon demand, to take such action necessary such that all Lenders share in the benefits of such collateral ratably in proportion to their respective Pro Rata Shares of the Aggregate Outstanding Credit Exposure. In case any such payment is disturbed by legal process, or otherwise, appropriate further adjustments will be made.

6.12 Environmental Indemnities. Each of the Credit Parties hereby agrees to

indemnify, defend and hold harmless the Lenders and their respective officers, directors, employees, agents, consultants, attorneys, contractors and their respective affiliates, successors or assigns, or transferees from and against, and reimburse said Persons in full with respect to, any and all loss, liability, damage, fines, penalties, costs and expenses, of every kind and character, including reasonable attorneys' fees and court costs, known or unknown, fixed or contingent, occasioned by or associated with any claims, demands, causes of action, suits and/or enforcement actions, including any administrative or judicial proceedings, and any remedial, removal or response actions ever asserted, threatened, instituted or requested by any Persons, including any Tribunal, arising out of or related to: (a) the breach of any representation or warranty of the Credit Parties contained in Section 5.16; (b) the failure of the Credit Parties to perform any of their respective covenants contained in Section 6.7; (c) the ownership, construction, occupancy, operation, use of the Credit Parties' properties prior to the earlier of the date on which (i) the Indebtedness and obligations secured hereby have been paid and performed in full and the Collateral Documents have been released, or (ii) the Credit Parties' properties has been sold by Agent or by the Lenders following such parties' ownership of the Credit Parties' properties by way of foreclosure of the Liens granted pursuant hereto, deed in lieu of such foreclosure or otherwise (the "Release Date"); provided, however, this indemnity shall not apply with respect to matters caused by or arising solely from the Agent's or the Lenders' activities

during any period of time the Agent or the Lenders acquire ownership of the Credit Parties' properties.

The indemnities contained in this Section 6.12 apply, without limitation, to any violation on or before the Release Date of any Environmental Laws and any liability or obligation relating to the environmental conditions on, under or about the Credit Parties' properties on or prior to the Release Date (including, without limitation: (a) the presence on, upon or in the Credit Parties' properties or release, discharge or threatened release on, upon or from the Credit Parties' properties of any polluting substances generated, used, stored, treated, disposed of or otherwise released prior to the Release Date, and (b) any and all damage to real or personal property or natural resources and/or harm or injury including wrongful death, to persons alleged to have resulted from such release of any polluting substances regardless of whether the act, omission, event or circumstances constituted a violation of any Environmental Law at the time of its existence or occurrence). The term "release" shall have the meaning specified in applicable Environmental Laws and the terms "stored," "treated" and "disposed" shall have the meanings specified in applicable Environmental Laws; provided, however, any broader meanings of such terms provided by applicable laws of the State of Oklahoma shall apply.

The provisions of this Section 6.12 shall be in addition to any other obligations and liabilities Credit Parties may have to the Agent or the Lenders at common law and shall survive the Release Date and shall continue thereafter in full force and effect. The Agent and the Lenders agree that in the event that such claim, suit or enforcement action is asserted or threatened in writing or instituted against them or any of their officers, employers, agents or contractors or any such remedial, removal or response action is requested of them or any of their officers, employees, agents or contractors for which the Agent or the Lenders may desire indemnity or defense hereunder, the Agent or the Lenders shall give prompt written notification thereof to the Credit Parties.

Notwithstanding anything to the contrary stated herein, the indemnities created by this Section 6.12 shall only apply to losses, liabilities, damages, fines, penalties, costs and expenses actually incurred by the Agent or the Lenders as a result of claims, demands, actions, suits or proceedings brought by Persons who are not the beneficiaries of any such indemnity. The Agent or the Lenders shall act as the exclusive agent for all indemnified Persons under this Section 6.12. With respect to any claims or demands made by such indemnified Persons, the Agent shall notify Unit within ten (10) days after the Agent's receipt of a writing advising the Agent of such claim or demand. Such notice shall identify (i) when such claim or demand was first made, (ii) the identity of the Person making it, (iii) the indemnified Person and (iv) the substance of such claim or demand. Failure by the Agent to so notify Unit within said ten (10) day period shall reduce the amount of the Credit Parties' obligations and liabilities under this Section 6.12 by an amount equal to any damages or losses suffered by the Credit Parties resulting from any prejudice caused the Credit Parties by such delay in notification from the Agent. Upon receipt of such notice, the Credit Parties shall have the exclusive right and obligation to contest, defend, negotiate or settle any such claim or demand through counsel of their own selection (but reasonably satisfactory to the Agent and the Lenders) and solely at Credit Parties' own cost, risk and expense; provided, that the

Agent and the Lenders, at their own cost and expense, shall have

the right to participate in any such contest, defense, negotiations or settlement. The settlement of any claim or demand hereunder by the Credit Parties, unless such settlement fully releases the Lenders from any and all liability thereon, may be made only upon the prior approval of the Lenders of the terms of the settlement, which approval shall not be unreasonably withheld.

ARTICLE VII

NEGATIVE COVENANTS

7.1. Dividends. The Credit Parties will not, nor will they permit any Subsidiary to, declare or pay any dividends or make any distributions on its capital stock (other than dividends payable in their own capital stock) or redeem, repurchase or otherwise acquire or retire any of its capital stock at any time outstanding, except that any (i) Subsidiary may declare and pay dividends or make distributions to Unit or to a Wholly-Owned Subsidiary of Unit and (ii) during any fiscal year Unit may pay cash dividends in amounts not exceeding twenty-five percent (25%) of its Consolidated Net Income (after taxes) for the preceding fiscal year.

7.2. Indebtedness. The Credit Parties will not create, incur or suffer to exist any Indebtedness, except:

(i) The Loans and the Reimbursement Obligations.

(ii) Indebtedness existing on the date hereof and described in the Disclosure Schedule.

(iii) Indebtedness arising under Rate Management Agreements permitted by Section 7.10.

(iv) Contingent Obligations permitted by Section 7.9.

(v) Non-recourse Indebtedness in a restricted or special purpose Subsidiary (for which consent of the Required Lenders must be obtained) and as to which none of Credit Parties (i) provides any guaranty or credit support of any kind (including any undertaking, guarantee, indemnity, agreement or instrument that would constitute Indebtedness) or (ii) is directly or indirectly liable (as a guarantor or otherwise); provided, that after giving effect to such Indebtedness outstanding from time to time, the Credit Parties are not in violation of any of the financial covenants of Article VIII.

(vi) Normal and ordinary course trade debt and customary obligations relating to the operation of oil and gas producing properties and drilling rigs.

(vii) Unsecured senior indebtedness not in excess of $7,500,000 in the aggregate.

(viii) Lease obligations (including building and office leases and leases

for equipment) not in excess of $10,000,000 in the aggregate.

(ix) usual and customary insurance premium financed in the normal course of business.

(x) indebtedness regarding self insured liabilities, including retentions under insurance policies.

(xi) miscellaneous items of Indebtedness not described in subsections

(i) through (viii) above which do not in the aggregate (taking into account all such Indebtedness of the Credit Parties) exceed $2,000,000 at any one time outstanding.

7.3. Limitation on Fundamental Changes. Credit Parties will not enter into any merger, consolidation or amalgamation, or liquidate, wind up or dissolve

itself (or suffer any liquidation or dissolution), or convey, sell, lease, assign, transfer or otherwise dispose of, all or substantially all of its property, business or assets, or make any material change in its present method of conducting business, except:

(a) any Subsidiary of a Credit Party may be merged or consolidated with or into such Credit Party (provided that such Credit Party will be the continuing or surviving business entity or other entity) or with or into any one or more wholly owned Subsidiaries of the Credit Party that is a Borrower or Subsidiary Guarantor (provided that the wholly owned Borrower or Subsidiary Guarantor will be the continuing or surviving business entity or other entity); and

(b) any Wholly Owned Subsidiary may sell, lease, transfer or otherwise dispose of any or all of its assets (upon voluntary liquidation or otherwise) to such Borrower or any other Wholly Owned Subsidiary of such Borrower that is a Borrower or Subsidiary Guarantor.

(c) so long as no Default will exist or be caused as a result, a Person may be merged or consolidated with or into a Borrower so long as the Borrower is the continuing or surviving corporation.

7.4. Sale of Assets. The Credit Parties will not lease, sell or otherwise dispose of its Property to any other Person, except:

(i) Sales of inventory in the ordinary course of business or the sale of assets not included in the Borrowing Base during any fiscal year in the aggregate gross amount of $2,000,000 or less.

(ii) Disposition of equipment and other personal property that is replaced by equivalent property or consumed in the normal operation of its Property.

(iii) Dispositions of a portion of its Property in connection with operating agreements, farmouts, farmins, joint exploration and development agreements and other agreements customary in the oil and gas industry that are entered into for the purposes of developing its Property and under which it receives relatively equivalent consideration.

(iv) Leases, sales or other dispositions of its Property that, together with all other Property of the Credit Parties and their Subsidiaries previously leased, sold or disposed of (other than (i), (ii) and (iii) above) as permitted by this Section during the period since the most recent Determination Date, do not constitute more than ten percent (10%) of the Engineered Value of the Borrowing Base Properties as determined by Administrative Agent in its sole discretion; further provided, however, to the extent such aggregate consideration for all asset sales or other dispositions of Properties exceeds five percent (5%) of the Borrowing Base during any period between semi-annual Determination Dates, the Required Lenders will have the option to reduce the Borrowing Base by the amount of such proceeds and, further, provided, that any resulting Deficiency (as defined in Section 2.6.6) must be cured by the Credit Parties in accordance with Section 2.8(b).

(v) Interests in oil and gas properties, portions thereof, to which no proved reserves of oil, gas or other liquid or gaseous hydrocarbons are properly attributed.

(vi) Sale of Property by Petroleum Supply Company in the ordinary course of its existing business operations.

7.5. Investments and Acquisitions. The Credit Parties will not make or suffer to exist any Investments (including without limitation, loans and advances to, and other Investments in, Subsidiaries), or commitments therefor, or to create any Subsidiary or to become or remain a partner in any partnership or joint venture, or to make any Acquisition of any Person, except:

(i) Cash Equivalent Investments.

(ii) Investments between Credit Parties or in any Credit Party's Subsidiaries which are Subsidiary Guarantors or Subsidiaries of any Credit Party with respect to which 100% of its Equity has been pledged to Administrative Agent.

(iii) Investments in existence on the date hereof and described on the Disclosure Schedule.

(iv) Investments in associations, joint ventures, and other relationships (a) that are established pursuant to standard form operating agreements or similar agreements or which are partnerships for purposes of federal income taxation only, (b) that are not corporations or partnerships (or subject to the Uniform

Partnership Act or other applicable state partnership act) under applicable state law, or (c) whose businesses are limited to the exploration, development and operation of oil, gas or mineral properties and interests owned directly by the parties in such associations, joint ventures or relationships in which the ownership interest of any Credit Party or its Subsidiary is in direct proportion to the amount of such Investment.

(v) Investments in Subsidiaries of the Credit Parties that are not Material Subsidiaries which do not exceed $5,000,000 in the aggregate during any fiscal year of Unit.

(vi) Miscellaneous items of Investments not described in clauses (i) through (v) above which do not (taking into account all such Investments of the Credit Parties and their Subsidiaries) exceed an aggregate amount of $5,000,000 during any fiscal year of Unit.

7.6. Liens. The Credit Parties will not create, incur, or suffer to exist any Lien in, of or on the Property of the Credit Parties or any of their Subsidiaries, except:

(i) Liens for taxes, assessments or governmental charges or levies on its Property if the same will not at the time be delinquent or thereafter can be paid without penalty, or are being contested in good faith and by appropriate proceedings and for which adequate reserves in accordance with GAAP will have been set aside on its books.

(ii) Liens imposed by law, such as carriers', warehousemen's and mechanics' liens and other similar liens arising in the ordinary course of business which secure payment of obligations not more than 90 days past due or which are being contested in good faith by appropriate proceedings and for which adequate reserves, in accordance with GAAP, will have been set aside on its books.

(iii) Liens arising out of pledges or deposits under worker's compensation laws, unemployment insurance, old age pensions, or other social security or retirement benefits, or similar legislation.

(iv) Utility easements, building restrictions and such other encumbrances or charges against real property as are of a nature generally existing with respect to properties of a similar character and which do not in any material way affect the marketability of the same or interfere with the use thereof in the business of the Credit Parties or their Subsidiaries.

(v) Liens existing on the date hereof and described on the Disclosure Schedule.

(vi) Liens in favor of the Administrative Agent, for the benefit of the Lenders, granted pursuant to any Collateral Document.

(vii) Liens on Property other than Collateral to secure not more than $1,000,000 in the aggregate of the Indebtedness permitted by Section 7.2(v).

(viii) With respect to Property subject to any Collateral Document, Liens burdening such Property that are expressly allowed by such Collateral Document.

(ix) Liens arising under operating agreements, unitization, pooling agreements and other agreements customary in the oil and gas industry securing amounts owed to operators and joint owners of oil and gas properties that will not at the time be delinquent, or

thereafter can be paid without penalty, or are being contested in good faith and by appropriate proceedings and for which adequate reserves in accordance with GAAP will have been set aside on its books.

(x) Contracts, agreements, instruments, obligations, defects and irregularities affecting the Property that individually or in the aggregate are not such as to interfere materially with the use, operation or value of the Property.

(xi) Any lien existing on any asset prior to its acquisition by a Borrower or one of its Subsidiaries and not created in contemplation of the acquisition.

(xii) Any extension, renewal or replacement (or successive extensions, renewals or replacements), as a whole or in part, of any Liens referred to in (i) - (xi) above for amounts not exceeding the principal amount of the indebtednesssecured by the Lien so extended, renewed or replaced.

7.7. Affiliates. The Credit Parties will not enter into any transaction (including, without limitation, the purchase or sale of any Property or service) with, or make any payment or transfer to, any Affiliate except in the ordinary course of business and pursuant to the reasonable requirements of the Credit Parties' or such Subsidiary's business and on fair and reasonable terms no less favorable to the Credit Parties or such Subsidiary than the Credit Parties or such Subsidiary would obtain in a comparable arms-length transaction.

7.8. Sale and Leaseback Transactions and other Off-Balance Sheet Liabilities. The Credit Parties will not enter into or suffer to exist any (i) Sale and Leaseback Transaction or (ii) any other transaction pursuant to which it incurs or has incurred Off-Balance Sheet Liabilities, except for Rate Management Obligations permitted to be incurred under the terms of Section 7.10.

7.9. Contingent Obligations. The Credit Parties will not make or suffer to exist any Contingent Obligation (including, without limitation, any Contingent Obligation with respect to the obligations of a Subsidiary), except (i) by endorsement of instruments for deposit or collection in the ordinary course of business, (ii) the Reimbursement Obligations, (iii) the Subsidiary Guaranty, (iv) other Contingent Obligations not to exceed an outstanding aggregate amount of $10,000,000 at any time, and (v) liabilities associated or accrued for abandonment and

plugging of Credit Parties' oil and gas properties, and (vi) as general partner of the limited partnerships formed annually to allow employees and directors of Unit to participate in certain of its oil and gas exploration and production operations.

7.10. Financial Contracts. None of Credit Parties will be a party to or in any manner be liable on any Financial Contract except:

(a) contracts entered into with the purpose and effect of fixing prices on oil or gas expected to be produced by the Credit Parties and their Subsidiaries, provided that at all times: (i) no such contract fixes a price for a term of more than 36 months; (ii) the aggregate monthly production covered by all such contracts for any single month does not in the aggregate exceed 80% of the aggregate Engineered Projected Production (as defined below) of the Credit Parties and their Subsidiaries anticipated to be sold in the ordinary course of their businesses for such month, (iii) no such contract requires the Credit Parties or any of their Subsidiaries to put up money, assets, letters of credit or other security against the event of its nonperformance prior to actual default by such Credit Parties or any of their Subsidiaries in performing their obligations thereunder (unless such counterparty is a Lender), and (iv) each such contract is with a counterparty or has a guarantor of the obligation of the counterparty who (unless such counterparty is a Lender or one of its Affiliates) at the time the contract is made has long-term obligations rated BBB+ or Baal or better, respectively, by either Moody's or S&P. As used in this subsection, the term "Engineered Projected Production" means the Engineered Value of projected production of oil or gas (measured by volume unit or BTU equivalent, not sales price) for the term of the contracts or a particular month, as applicable, from properties and interests owned by the Credit Parties and their Subsidiaries that are located in or offshore of the United States and are proved developed producing reserves (as determined by the Administrative Agent in its oil and gas lending criteria), as such production is projected in the most recent report delivered pursuant to Section 6.1(vii) or (viii), after deducting projected production from any

properties or interests sold or under contract for sale that had been included in such report and after adding projected production from any properties or interests that had not been reflected in such report but that are reflected in a separate or supplemental reports meeting the requirements of such Section 6.1(vii) or (viii) above and otherwise are satisfactory to Administrative Agent;

(b) contracts entered into by Credit Parties or their Subsidiaries with the purpose and effect of fixing interest rates on a principal amount of indebtedness of such Credit Parties or their Subsidiaries that is accruing interest at a variable rate, provided that no such contract will be entered into by Credit Parties or any of their Subsidiaries for speculative purposes; and

(c) such contracts comply with the Rate Management Transactions' criteria disclosed in writing to the Administrative Agent.

7.11. Letters of Credit. The Credit Parties will not apply for or become liable upon or in respect of any Letter of Credit other than LCs.

7.12. Prohibited Contracts. Except as expressly permitted in this Agreement or the other Loan Documents, none of Credit Parties will, directly or indirectly, enter into, create, or otherwise allow to exist any contract or other consensual restriction on the ability of any Subsidiary of a Borrower to: (a) pay dividends or make other distributions to other Credit Parties, (b) to redeem equity interests held in it by other Credit Parties, or (c) to repay loans and other indebtedness owing by it to other Credit Parties. None of the Credit Parties or their Subsidiaries will amend or permit any amendment to any contract or lease which releases, qualifies, limits, makes contingent or otherwise detrimentally affects the rights and benefits of the Administrative Agent or any Lender under or acquired pursuant to any Collateral Documents.

7.13. Negative Pledge. Except only for Liens permitted by applicable subsections of Section 7.6, none of the Credit Parties will cause or permit the pledging, encumbrance, mortgaging, granting of a consensual security interest or any other type of pledge, charge or imposition of a Lien against any of the Credit Parties' or any Subsidiaries' (including without limitation, PetroCorps') oil and gas mining and mineral interests, rights and properties, proved, developed, producing or otherwise (whether now owned or hereafter created or acquired) constituting 100% of the Engineered Value thereto, to secure any Indebtedness (including Contingent Obligations) without the prior written consent of the Administrative Agent and the Lenders. This covenant, to the fullest extent permitted by applicable law, will be deemed and construed as a "negative pledge" of all such oil and gas mining and mineral interests in favor of the Administrative Agent for the benefit of the Lenders.

ARTICLE VIII

FINANCIAL COVENANTS

8.1. Current Ratio. Unit will not permit the ratio, determined as of the end of each of Unit's fiscal quarters, of (i) Unit's consolidated Current Assets (including the then Available Aggregate Commitment) to (ii) Unit's consolidated Current Liabilities (including the current portion of the Loans), to be less than 1.0 to 1.0.

8.2. Leverage Ratio. Unit will not permit the ratio, determined as of the end of each of Unit's fiscal quarters, of (i) Long Term Debt to (ii) Consolidated EBITDA for the then mostrecently ended rolling four (4) fiscal quarters to be greater than 3.25 to 1.0.

8.3. Minimum Consolidated Net Worth. Unit will not permit Unit's Consolidated Net Worth to be less than Three Hundred Fifty Million Dollars ($350,000,000) as tested quarterly effective as of the close of each fiscal quarter of Unit and annually effective as of the close of each fiscal year end, based on the quarterly and annual financial statement reporting requirements of Section 6.1(i) and (ii), respectively.

ARTICLE IX

COLLATERAL AND GUARANTEES

9.1. Collateral. At all times the Secured Obligations will be secured by first and prior Liens (subject only to Permitted Encumbrances) covering and encumbering the Rigs described on Schedule 1 annexed to the Second Amended and Restated Security Agreement dated as of even date with this Agreement from Unit Drilling Company, as debtor, in favor of the Administrative Agent , as collateral agent for the Lenders (the "Security Agreement"), together with all associated equipment, machinery, tools, gear, accessions, accessories, and other apparatus or goods with the Rigs.

9.2. Additional Collateral. Subject to the occurrence of the events described below in Section 9.2(a) and 9.2(b), Credit Parties will grant to the Administrative Agent as collateral agent for the Lenders a first mortgage lien and/or deed of trust on and security interest in all of Credit Parties' oil and gas properties and related inventory, intangibles, accounts, equipment, fixtures and personal property (collectively referred to as the "Additional Collateral") to secure the Obligations, by instruments satisfactory to the Administrative Agent and the Lenders, as follows:

(a) No later than thirty (30) days after the Administrative Agent notifies Unit in writing that the aggregate amount of Outstanding Credit Exposure exceeds the lesser of the (i) then applicable aggregate Commitment Amount or (ii) Borrowing Base then in effect if, by the last day of said thirty (30) day period, Credit Parties have not made a payment on the aggregate balance of the Notes in an amount equal to such excess, plus the unpaid accrued interest on the amount so paid as of the date of such payment, all in accordance with the provisions of Section 2.6.6(b) of this Agreement.

(b) No later than thirty (30) days after the Administrative Agent notifies Unit in writing that an Event of Default has occurred, unless circumstances giving rise to such Event of Default have been cured prior to the lapse of such thirty (30) days.

9.3. Rig Appraisals. The Administrative Agent, on behalf of the Required Lenders, will be entitled to request that Unit obtain an updated, current appraisal of the Rigs from Harvey Davis or another drilling rig appraiser acceptable to the Administrative Agent and the Required Lenders not more frequently than once every two (2) calendar years, commencing calendar year 2004, at Unit's sole cost and expense. Upon receipt of such written request from the Administrative Agent, Unit will diligently engage such acceptable appraiser and deliver a full and complete copy of the appraisal of the Rigs no later than ninety (90) days after receipt of the Agent's written request.

9.4. Guarantees. Unit will cause each current Material Subsidiary (consisting of PetroCorp upon the concurrent consummation of the PetroCorp merger contemplated by the PetroCorp Agreement) and each future Material Subsidiary to guarantee the prompt payment and performance when due of the Obligations in accordance with the terms and provisions of the Subsidiary Guaranty. As soon as practicable and in any event within ten (10) days after any Person becomes a direct or indirect Material Subsidiary, Unit will provide the Administrative

Agent written notice thereof and will cause such Person to execute a Subsidiary Guaranty Joinder Agreement in substantially the same form as Schedule 1 to the Subsidiary Guaranty. Prior to any Investments being permitted to be made in any other Subsidiary of the Credit Parties in excess of the amount permitted by Section 7.5(v) such Subsidiary will also execute and deliver such a Subsidiary Guaranty to the Administrative Agent for the ratable benefit of each Lender, together with such other certificates or documents as Administrative Agent reasonably deems necessary or appropriate to confirm such Subsidiary Guaranty, including without limitation, closing opinions (supplementing the closing opinion required by Section 4.1.1(v) of this Agreement) as required by the Administrative Agent or the Required Lenders in connection with the Subsidiary Guaranty instruments executed from time to time by Material Subsidiaries under this Section 9.14 (including PetroCorp as the initial Subsidiary Guarantor).

9.5. Further Assurances. Unit agrees to deliver and to cause each other Borrower and its Subsidiaries to deliver, to further secure the Secured Obligations whenever requested by Administrative Agent in its sole and absolute discretion, deeds of trust, mortgages, chattel mortgages, security agreements, financing statements and other Collateral Documents in form and substance satisfactory to Administrative Agent for the purpose of granting, confirming, and perfecting first and prior liens or security interests in any real or personal property which is at such time Collateral or which was intended to be

Collateral pursuant to any Collateral Document previously executed and not then released by Administrative Agent.

9.6. Negative Pledge/Production Proceeds. Notwithstanding that, by the terms hereof, the Credit Parties and their Subsidiaries are granting to Administrative Agent and Lenders a "negative pledge" of all of the "production proceeds" accruing to the property covered thereby, so long as no Default has occurred Credit Parties and their Subsidiaries may continue to receive from the purchasers of production all such production proceeds. Upon the occurrence of a Default, Administrative Agent and Lenders may exercise all rights and remedies granted under the Collateral Documents, including the right to obtain possession of all production proceeds then held by Credit Parties and their Subsidiaries or to receive directly from the purchasers of production all production proceeds.

ARTICLE X

DEFAULTS

The occurrence of any one or more of the following events will constitute a Default:

10.1. Any representation or warranty made or deemed made by or on behalf of the Credit Parties to the Lenders or the Administrative Agent under or in connection with this Agreement, any Credit Extension, or any certificate, report or information delivered in connection with this Agreement or any other Loan Document is materially false on the date as of which made.

10.2. Nonpayment of principal of any Loan when due, nonpayment of any Reimbursement Obligation within one Business Day after the same becomes due, or nonpayment

of interest upon any Loan or of any commitment fee, LC Fee or other obligations under any of the Loan Documents within ten (10) days after the same becomes due.

10.3. The breach by the Credit Parties of any of the terms or provisions of Section 2.21, Section 6.3, Article VII, Article VIII or Article IX of this Agreement and failure to cure within twenty (20) days following written notice from the Administrative Agent or any Lender to Unit.

10.4. The breach by the Credit Parties (other than a breach which constitutes a Default under another Section of this Article X) of any of the terms or provisions of this Agreement which is not remedied within thirty (30) days after written notice from the Administrative Agent or any Lender to Unit.

10.5. Failure of the Credit Parties to pay when due any Material Indebtedness; or the default by the Credit Parties in the performance (beyond the applicable grace period with respect thereto, if any) of any term, provision or condition contained in any Material Indebtedness Agreement, or any other event occurs or condition exists, the effect of which default, event or condition is to cause, or to permit the holder(s) of such Material Indebtedness or the lender(s) under any Material Indebtedness Agreement to cause, such Material Indebtedness to become due prior to its stated maturity or any commitment to lend under any Material Indebtedness Agreement to be terminated prior to its stated expiration date; or any Material Indebtedness of the Credit Parties or any of their Subsidiaries will be declared to be due and payable or required to be prepaid or repurchased (other than by a regularly scheduled payment) prior to the stated maturity thereof; or the Credit Parties will not pay, or admit in writing its inability to pay, its debts generally as they become due.

10.6. The Credit Parties or any of their Material Subsidiaries will (i) have an order for relief entered with respect to it under the Federal bankruptcy laws as now or hereafter in effect, (ii) make an assignment for the benefit of creditors, (iii) apply for, seek, consent to, or acquiesce in, the appointment of a receiver, custodian, trustee, examiner, liquidator or similar official for it or any Substantial Portion of its Property, (iv) institute any proceeding seeking an order for relief under the Federal bankruptcy laws as now or hereafter in effect or seeking to adjudicate it a bankrupt or insolvent, or seeking dissolution, winding up, liquidation, reorganization, arrangement, adjustment or composition of it or its debts under any law relating to bankruptcy, insolvency or reorganization or relief of debtors or fail to file an answer or other pleading denying the material allegations of any such proceeding filed against it, (v) take any corporate or partnership action to authorize or effect any of the foregoing actions set forth in this Section 10.6 or (vi) fail

to contest in good faith any appointment or proceeding described in Section 10.7.

10.7. Without the application, approval or consent of the Credit Parties or any of their Material Subsidiaries, a receiver, trustee, examiner, liquidator or similar official will be appointed for the Credit Parties or any of their Material Subsidiaries or a proceeding described in Section 10.6(iv) will be instituted against the Credit Parties or any of their Material Subsidiaries and such appointment continues undischarged or such proceeding continues undismissed or unstayed for a period of 60 consecutive days.

10.8. Any court, government or governmental agency condemns, seizes or otherwise appropriates, or takes custody or control of, all or any portion of the Property of the Credit Parties and their Material Subsidiaries which, when taken together with all other Property of the Credit Parties and their Material Subsidiaries so condemned, seized, appropriated, or taken custody or control of, during the twelve-month period ending with the month in which any such action occurs, constitutes a Material Adverse Effect.

10.9. The Credit Parties or any of their Material Subsidiaries fails within 30 days to pay, bond or otherwise discharge one or more (i) judgments or orders for the payment of money in excess of $1,000,000 (or the equivalent thereof in currencies other than U.S. Dollars) in the aggregate, or (ii) nonmonetary judgments or orders which, individually or in the aggregate, could reasonably be expected to have a Material Adverse Effect, which judgment(s), in any such case, is/are not stayed on appeal or otherwise being appropriately contested in good faith.

10.10. The Unfunded Liabilities of all Single Employer Plans exceeds in the aggregate $500,000 or any material Reportable Event occurs in connection with any Plan.

10.11. Nonpayment by the Credit Parties or any Material Subsidiary of any Rate Management Obligation when due or the breach by the Credit Parties or any Subsidiary of any term, provision or condition contained in any Rate Management Transaction or any transaction of the type described in the definition of "Rate Management Transactions," whether or not any Lender or Affiliate of a Lender is a party thereto, after taking into account any applicable grace period, but only if such nonpayment or breach constitutes a Material Adverse Effect.

10.12. Any Change in Control of any of the Credit Parties occurs.

10.13. The Credit Parties or any of their Material Subsidiaries (i) are the subject of any proceeding or investigation pertaining to the release by the Credit Parties, any of their Material Subsidiaries or any other Person of any toxic or hazardous waste or substance into the environment, or (ii) violate any Environmental Law, which, in the case of an event described in clause (i) or clause (ii), could reasonably be expected to have a Material Adverse Effect.

10.14. Any Subsidiary Guaranty fails to remain in full force or effect or any action is taken to discontinue or to assert the invalidity or unenforceability of any Subsidiary Guaranty, or any Subsidiary Guarantor fails to comply with any of the terms or provisions of any Subsidiary Guaranty to which it is a party, or any Subsidiary Guarantor denies that it has any further liability under any Subsidiary Guaranty to which it is a party, or will give notice to such effect.

10.15. Any Collateral Document for any reason fails to create a valid and perfected first priority security interest in any collateral purported to be covered thereby, except as permitted by the terms of any Collateral Document, or any Collateral Document fails to remain in full force or effect; or any action by the Credit Parties or any of their Subsidiaries is taken to discontinue or to assert the invalidity of unenforceability of any Collateral Document.

10.16. The Credit Parties fails to comply in any material respect with any of the terms or provisions of any Collateral Document.

10.17. The representations and warranties set forth in Section 5.15 ("Plan Assets; Prohibited Transactions") at any time are not true and correct in any material respect.

ARTICLE XI

ACCELERATION, WAIVERS, AMENDMENTS AND REMEDIES

11.1. Acceleration.

(i) If any Default described in Section 10.6 or 10.7 occurs with respect to the Credit Parties, the obligations of the Lenders to make Loans hereunder and the obligation and power of the LC Issuer to issue LCs will automatically terminate and the Obligations will immediately become due and payable without any election or action on the part of the Administrative Agent, the LC Issuer or any Lender and the Credit Parties will be and become thereby unconditionally obligated, without any further notice, act or demand, to pay to the Administrative Agent an amount in immediately available funds equal to the amount of LC Obligations in cash or cash equivalents satisfactory to the Administrative Agent. If any other Default occurs and is continuing, the Required Lenders (or the Administrative Agent with the consent of the Required Lenders) may (a) terminate or suspend the obligations of the Lenders to make Loans hereunder and the obligation and power of the LC Issuer to issue LCs, or declare the Obligations to be due and payable, or both, in which event the Obligations will become immediately due and payable, without presentment, demand, protest or notice of any kind, all of which the Credit Parties hereby expressly waive, and (b) upon notice to the Credit Parties and in addition to the continuing right to demand payment of all amounts payable under this Agreement, make demand on the Credit Parties to pay, and the Credit Parties will, forthwith upon such demand and without any further notice or act, immediately pay to the Administrative Agent the amount of such LC Obligations.

(ii) The Administrative Agent may at any time or from time to time, after such funds are deposited with the Administrative Agent, apply such funds to the payment of the Obligations and any other amounts as may have become due and payable by the Credit Parties to the Lenders or the LC Issuer under the Loan Documents.

11.2. Amendments. Subject to the provisions of this Section 11.2, the Required Lenders (or the Administrative Agent with the consent in writing of the Required Lenders) and the Credit Parties may enter into supplemental agreements for the purpose of adding or modifying any provisions to the Loan Documents or changing in any manner the rights of the Lenders or the Credit Parties under this Agreement or waiving any Default under this Agreement; provided, however, that no such supplemental agreement will, without the consent of all of the Lenders:

(i) Extend the final maturity of any Loan, or extend the expiration date of an LC to a date after the Facility Termination Date or postpone any regularly scheduled payment of principal of any Loan or forgive all or any portion of the principal amount thereof or any Reimbursement Obligation related thereto, or reduce the rate or extend the time of payment of interest or fees thereon or Reimbursement Obligations related thereto.

(ii) Reduce the percentage specified in the definition of Required Lenders or eliminate or delete the Borrowing Base concept of Section 2.6 of this Agreement.

(iii) Extend the Facility Termination Date, or reduce the amount or extend the payment date for, the mandatory principal payments required under Section 2.8(b), or increase the (a) Maximum Credit Amount, (b) Aggregate Commitment Amount above the Maximum Credit Amount, (c) Borrowing Base contrary to the last sentence of Section 2.6.2(b), (d) amount of the Commitment of any Lender under this Agreement or (e) commitment to issue LCs.

(iv) Amend this Section 11.2 or permit the Credit Parties to assign their rights under this Agreement.

(v) Release any Subsidiary Guarantor of any Advance or, except as provided in the Collateral Documents, release all or substantially all of the Collateral or delete the Additional Collateral provisions of Section 9.2. No amendment of any provision of this Agreement relating to the Administrative Agent will be effective without the written consent of the Administrative Agent, and no amendment of any provision relating to the LC Issuer will be effective without the written consent of the LC Issuer.

11.3. Preservation of Rights. No delay or omission of the Lenders, the LC Issuer or the Administrative Agent to exercise any right under the Loan Documents will impair such right or be construed to be a waiver of any Default or an acquiescence in such Default, and the making of a Credit Extension notwithstanding the existence of a Default or the inability of the Credit Parties to satisfy the conditions precedent to such Credit Extension will not constitute any waiver or acquiescence. Any single or partial exercise of any such right will not preclude other or further exercise of such right or the exercise of any other right, and no waiver, amendment or other variation of the terms, conditions or provisions of the Loan Documents whatsoever will be valid unless in writing signed by the Lenders required pursuant to Section 11.2, and then only to the extent specifically set forth in writing. All remedies contained in the Loan Documents or by law or equity afforded will be cumulative and will be available to the Administrative Agent, the LC Issuer and the Lenders until the Obligations have been paid in full.

ARTICLE XII

GENERAL PROVISIONS

12.1. Survival of Agreements. All covenants, agreements, representations and warranties contained in this Agreement will survive the making of the Credit Extensions during the term of this Agreement and any extensions, renewals, supplements or restatements of this Agreement.

12.2. Governmental Regulation. Anything contained in this Agreement to the contrary notwithstanding, neither the LC Issuer nor any Lender will be obligated to extend credit to the Credit Parties in violation of any limitation or prohibition provided by any applicable statute or regulation.

12.3. Headings. Section headings in the Loan Documents are for convenience of reference only, and will not govern the interpretation of any of the provisions of the Loan Documents.

12.4. Entire Agreement. The Loan Documents embody the entire agreement and understanding among the Borrowers, the Administrative Agent, the LC Issuer and the Lenders and supersede all prior agreements and understandings among the Borrowers, the Administrative Agent, the LC Issuer and the Lenders relating to the subject matter of the Loan Documents other than the Administrative Agent Fee Letter, all of which will survive and remain in full force and effect during the term of this Agreement.

12.5. Several Obligations; Benefits of this Agreement. The respective obligations of the Lenders hereunder are several and not joint and no Lender will be the partner or Administrative Agent of any other (except to the extent to which the Administrative Agent is authorized to act in such capacity). The failure of a Lender to perform any of its obligations hereunder will not relieve any other Lender from any of its obligations hereunder. This Agreement will not be construed so as to confer any right or benefit on any Person other than the parties to this Agreement and their respective successors and assigns.

12.6. Expenses; Indemnification.

(i) The Borrowers will reimburse the Administrative Agent and the Syndication Agent for any filing and recording fees, reasonable costs and out-of- pocket expenses (including reasonable attorneys' fees, time charges and expenses advanced of attorneys for the Administrative Agent or for any of the Lenders) paid or incurred by the Administrative Agent or the Syndication Agent in connection with the preparation, negotiation, execution, closing, delivery, syndication, review, amendment, waiver, consent or modification, restructure, refinancing, Lien perfection, administration, collection and enforcement of the Loan Documents, regardless of whether or not the transactions provided for in this Agreement are eventually closed and regardless of whether or not any or all sums evidenced by the Notes are advanced to the Borrowers by the Lenders.

(ii) The Credit Parties hereby also agree to indemnify the Administrative Agent, the Syndication Agent, the LC Issuer and each Lender, its directors, officers and employees against all losses, claims, damages, penalties,

judgments, liabilities and expenses (including, without limitation, all expenses of litigation or preparation therefor whether or not the Administrative Agent, the Syndication Agent, the LC Issuer or any Lender is a party to such litigation) which any of them may pay or incur in good faith as a result of this Agreement, the other Loan Documents, the transactions contemplated by the Loan Documents except to the extent that they are determined in a final non-appealable judgment by a court of competent jurisdiction to have resulted from the gross negligence or willful misconduct of the party seeking indemnification. The obligations of the Credit Parties under this Section 12.6 will survive the termination of this Agreement.

12.7. Severability of Provisions. Any provision in any Loan Document that is held to be inoperative, unenforceable, or invalid in any jurisdiction will, as to that jurisdiction, be inoperative, unenforceable, or invalid without affecting the remaining provisions in that jurisdiction or the operation, enforceability, or validity of that provision in any other jurisdiction. The provisions of all Loan Documents are severable.

12.8. Nonliability of Lenders. The relationship between the Borrowers on the one hand and the Lenders, the LC Issuer and the Administrative Agent on the other hand will, to the extent that relationship is the subject of this Agreement, be solely that of borrowers and lenders. Neither the Administrative Agent, the Syndication Agent, the LC Issuer nor any Lender will have any fiduciary responsibilities to the Credit Parties. Neither the Administrative Agent, the Syndication Agent, the LC Issuer nor any Lender undertakes any responsibility to the Credit Parties to review or inform the Credit Parties of any matter in connection with any phase of the Credit Parties' business or operations. The Borrowers agree that neither the Administrative Agent, the Syndication Agent, the LC Issuer nor any Lender will have liability to the Credit Parties (whether sounding in tort, contract or otherwise) for losses suffered by the Credit Parties in connection with, arising out of, or in any way related to, the transactions contemplated and the relationship established by the Loan Documents, or any act, omission or event occurring in connection therewith, unless it is determined in a final non-appealable judgment by a court of competent jurisdiction that such losses resulted from the gross negligence or willful misconduct of the party from which recovery is sought. Neither the Administrative Agent, the Syndication Agent, the LC Issuer nor any Lender will have any liability with respect to, and the Credit Parties hereby waive, release and agree not to sue for, any special, indirect or consequential damages suffered by the Credit Parties in connection with, arising out of, or in any way related to the Loan Documents or the transactions contemplated thereby.

12.9. Confidentiality. Each Lender agrees to hold as confidential any information which it may receive from the Borrowers pursuant to this Agreement in confidence, except for disclosure (i) to its Affiliates and to other Lenders and their respective Affiliates, (ii) to legal counsel, accountants, and other professional advisors to such Lender or to a Transferee, (iii) to regulatory officials, (iv) to any Person as requested pursuant to or as required by law, regulation, or legal process, (v) to any Person in connection with any legal proceeding to which such Lender is a party, (vi) to such Lender's direct or indirect contractual counterparties in swap agreements or to legal counsel, accountants and other professional advisors to such counterparties, (vii) permitted by Section 14.4, (viii) to rating agencies if requested or required by such agencies in

connection with a rating relating to the Advances, and (ix) of information that the Credit Parties have made available to the general public.

12.10. Disclosure. The Borrowers and each Lender hereby acknowledge and agree that BOk and/or its Affiliates from time to time may hold investments in, make other loans to or have other relationships with the Borrowers and/or their Subsidiaries.

12.11. Place of Payment. All amounts to be paid by the Borrowers or the Subsidiary Guarantors under this Agreement will be paid in immediately available funds to the Administrative Agent at its principal banking offices at Bank of Oklahoma Tower, One Williams Center, Tulsa, Oklahoma 74192, Attention: Energy Department -8th Floor, or at such other place as the Administrative Agent or the Required Lenders will notify Unit in writing. If any interest, principal or other payment falls due on a date other than a Business Day, then (unless otherwise provided in this Agreement) such due date will be extended to the next succeeding Business Day, and such extension of time will in such case be included in computing interest, if any, in connection with such payment.

12.12. Interest. It is the intention of the parties to this Agreement that the Lenders conform strictly to usury laws applicable to it. Accordingly, if the transactions contemplated by this Agreement would be usurious as to a Lender under laws applicable to it (including the laws of the United States of America or any other jurisdiction whose laws may be mandatorily applicable to Lenders notwithstanding the other provisions of this Agreement), then, in that event, notwithstanding anything to the contrary in any of the Loan Documents or any agreement entered into in connection with or as security for the Notes, it is agreed as follows:

(i) the aggregate of all consideration which constitutes interest under law applicable to Lenders that is contracted for, taken, reserved, charged or received by Lenders under any of the Loan Documents or agreements or otherwise in connection with the Notes will under no circumstances exceed the Highest Lawful Rate allowed by such applicable law, and any excess will be canceled automatically and if theretofore paid will be credited by the Administrative Agent or the Lenders on the principal amount of the Obligations (or, to the extent that the principal amount of the Obligations will have been or would thereby be paid in full, refunded by Administrative Agent or the Lenders to the Borrowers); and

(ii) in the event that the maturity of any of the Notes is accelerated by, because of or resulting from an Event of Default under this Agreement or otherwise, or in the event of any required or permitted prepayment, then such consideration that constitutes interest under law applicable to Administrative Agent or the Lenders may never include more than the maximum amount allowed by such applicable law, and excess interest, if any, provided for in this Agreement or otherwise will be canceled automatically by Lenders as of the date of such acceleration or prepayment and, if theretofore paid, will be credited by Administrative Agent or the Lenders on the principal amount of the Obligations

(or, to the extent that the principal amount of the Obligations will have been or would thereby be paid in full, refunded by Lenders to the Borrowers).

All sums paid or agreed to be paid to Administrative Agent or the Lenders for the use, forbearance or detention of sums due under this Agreement will, to the extent permitted by law applicable to Administrative Agent and/or the Lenders, be amortized, prorated, allocated and spread throughout the full term of the Loans evidenced by the Notes until payment in full so that the rate or amount of interest on account of any Loans under this Agreement does not exceed the Highest Lawful Rate allowed by such applicable law. If at any time and from time to time (i) the amount of interest payable to Lenders on any date will be computed at the highest lawful rate applicable to Lenders pursuant to this Section 12.12; and (ii) in respect of any subsequent interest computation period the amount of interest otherwise payable to Lenders would be less than the amount of interest payable to Lenders computed at the highest lawful rate applicable to such Lenders, then the amount of interest payable to Lenders regarding such subsequent interest computation period will continue to be computed at the Highest Lawful Rate applicable to Lenders until the total amount of interest payable to Lenders equals the total amount of interest which would have been payable to Lenders if the total amount of interest had been computed without giving effect to this Section 12.12.

None of the terms and provisions contained in this Agreement or in any other Loan Document which directly or indirectly relate to interest will ever be construed without reference to this Section 12.12, or be construed to create a contract to pay for the use, forbearance or detention of money at an interest rate in excess of the Highest Lawful Rate.

12.13. Automatic Debit of Borrowers' Operating Account. Upon Borrowers' failure to pay all such costs and expenses owed by Borrowers under Section 12.6 of this Agreement within thirty (30) days of the Administrative Agent's submission of invoices therefore, the Administrative Agent will pay such costs and expenses by debit to the operating account of Borrowers with the Administrative Agent without further or other notice to Borrowers.

12.14. Exceptions to Covenants. The Credit Parties are not permitted to take any action or fail to take any action which is permitted as an exception to

any of the covenants contained in this Agreement or which is within the permissible limits of any of the covenants contained in this Agreement if such action or omission would result in the breach of any other covenant contained in this Agreement.

12.15. Conflict with Security Instruments. To the extent the terms and provisions of any of the Security Instruments are in conflict with the terms and provisions hereof, this Agreement will be deemed controlling.

12.16. Lost Documents. On receipt of an affidavit of an officer of the Administrative Agent as to the loss, theft, destruction or mutilation of the Notes or Collateral Documents which

is not of public record, and, in the case of any mutilation, on the surrender and cancellation of the Notes or Collateral Documents, the Borrowers or any Subsidiary Guarantors will issue, in lieu thereof, a replacement Note(s) or other Collateral Documents in the same principal amount thereof (in the case of any of the Notes) and otherwise of like tenor.

ARTICLE XIII

THE ADMINISTRATIVE AGENT

13.1. Appointment; Nature of Relationship. BOk is hereby appointed by each of the Lenders as its contractual representative (herein referred to as the "Administrative Agent") hereunder and under each other Loan Document, and each of the Lenders irrevocably authorizes the Administrative Agent to act as the contractual representative of such Lender with the rights and duties expressly set forth herein and in the other Loan Documents. The Administrative Agent agrees to act as such contractual representative upon the express conditions contained in this Article XIII. Notwithstanding the use of the defined term "Administrative Agent," it is expressly understood and agreed that the Administrative Agent will not have any fiduciary responsibilities to any Lender by reason of this Agreement or any other Loan Document and that the Administrative Agent is merely acting as the contractual representative of the Lenders with only those duties as are expressly set forth in this Agreement and the other Loan Documents. In its capacity as the Lenders' contractual representative, the Administrative Agent (i) does not hereby assume any fiduciary duties to any of the Lenders, (ii) is a "representative" of the Lenders within the meaning of the term "secured party" as defined in the Oklahoma Uniform Commercial Code and (iii) is acting as an independent contractor, the rights and duties of which are limited to those expressly set forth in this Agreement and the other Loan Documents. Each of the Lenders hereby agrees to assert no claim against the Administrative Agent on any agency theory or any other theory of liability for breach of fiduciary duty, all of which claims each Lender hereby waives.

13.2. Powers. The Administrative Agent will have and may exercise such powers under the Loan Documents as are specifically delegated to the Administrative Agent by the terms of each thereof, together with such powers as are reasonably incidental thereto. The Administrative Agent has no implied duties to the Lenders, or any obligation to the Lenders to take any action thereunder except any action specifically provided by the Loan Documents to be taken by the Administrative Agent.

13.3. General Immunity. Neither the Administrative Agent nor any of its directors, officers or employees will be liable to the Credit Parties, the Lenders or any Lender for any action taken or omitted to be taken by it or them hereunder or under any other Loan Document or in connection herewith or therewith except to the extent such action or inaction is determined in a final non-appealable judgment by a court of competent jurisdiction to have arisen from the gross negligence or willful misconduct of such Person provided that nothing in this Section 13.3 is intended to impair or otherwise limit (i) the rights of the Credit Parties to make claims against the LC Issuer for damages as contemplated by either proviso (ii) to the first sentence of Section 2.19.6 or proviso (y) to the penultimate sentence of Section 2.19.9 or (ii) the liabilities of the LC Issuer or the Administrative Agent to the Credit Parties based on a standard of care otherwise

expressly designated or stipulated to in other provisions of this Agreement.

13.4. No Responsibility for Loans, Recitals. Neither the Administrative

Agent nor any of its directors, officers or employees will be responsible for or have any duty to ascertain, inquire into, or verify (a) any statement, warranty or representation made in connection with any Loan Document or any borrowing hereunder; (b) the performance or observance of any of the covenants or agreements of any obligor under any Loan Document, including, without limitation, any agreement by an obligor to furnish information directly to each Lender; (c) the satisfaction of any condition specified in Article IV, except receipt of items required to be delivered solely to the Administrative Agent; (d) the existence or possible existence of any Default; (e) the validity, enforceability, effectiveness, sufficiency or genuineness of any Loan Document or any other instrument or writing furnished in connection therewith; (f) the value, sufficiency, creation, perfection or priority of any Lien in any collateral security; or (g) the financial condition of the Credit Parties or any Subsidiary Guarantor of any of the Obligations or of any of the Credit Parties' or any such Subsidiary Guarantor 's respective Subsidiaries. The Administrative Agent has no duty to disclose to the Lenders information that is not required to be furnished by the Credit Parties to the Administrative Agent at such time, but is voluntarily furnished by the Credit Parties to the Administrative Agent (either in its capacity as Administrative Agent or in its individual capacity).

13.5. Action on Instructions of Lenders. The Administrative Agent will in all cases be fully protected in acting, or in refraining from acting, hereunder and under any other Loan Document in accordance with written instructions signed by the Required Lenders, and such instructions and any action taken or failure to act pursuant thereto will be binding on all of the Lenders. The Lenders hereby acknowledge that the Administrative Agent will be under no duty to take any discretionary action permitted to be taken by it pursuant to the provisions of this Agreement or any other Loan Document unless it is requested in writing to do so by the Required Lenders. The Administrative Agent will be fully justified in failing or refusing to take any action hereunder and under any other Loan Document unless it is first indemnified to its satisfaction by the Lenders pro rata against any and all liability, cost and expense that it may incur by reason of taking or continuing to take any such action.

13.6. Employment of Administrative Agents; Counsel; Reliance. The Administrative Agent may execute any of its duties as Administrative Agent hereunder and under any other Loan Document by or through employees, Administrative Agents, and attorneys-in-fact and is not answerable to the Lenders, except as to money or securities received by it or its authorized Administrative Agents, for the default or misconduct of any such Administrative Agents or attorneys-in-fact selected by it with reasonable care. The Administrative Agent will be entitled to advice of counsel concerning the contractual arrangement between the Administrative Agent and the Lenders and all matters pertaining to the Administrative Agent's duties hereunder and under any other Loan Document. The Administrative Agent will be entitled to rely upon any Note, notice, consent, certificate, affidavit, letter, telegram, statement, paper or document believed by it to be genuine and correct and to have been signed or sent by the proper person or persons, and, in respect to legal matters, upon the opinion of counsel selected by the Administrative Agent, which counsel may be employees of the Administrative Agent.

13.7. Administrative Agent's Reimbursement and Indemnification. The Lenders agree to reimburse and indemnify the Administrative Agent ratably in proportion to their respective Commitments (or, if the Commitments have been terminated, in proportion to their Commitments immediately prior to such termination) (i) for any amounts not reimbursed by the Borrowers for which the Administrative Agent is entitled to reimbursement by the Borrowers under the Loan Documents, (ii) for any other expenses incurred by the Administrative Agent on behalf of the Lenders, in connection with the preparation, execution, delivery, administration and enforcement of the Loan Documents (including, without limitation, for any expenses incurred by the Administrative Agent in connection with any dispute between the Administrative Agent and any Lender or between two or more of the Lenders) and (iii) for any liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any kind and nature whatsoever which may be imposed on, incurred by or asserted against the Administrative Agent in any way relating to or arising out of the Loan Documents or any other document delivered in connection therewith or the transactions contemplated thereby (including, without limitation, for any such amounts incurred by or asserted against the Administrative Agent in connection with any dispute between the Administrative Agent and any Lender or between two or more of the Lenders), or the enforcement of any of the terms of the Loan Documents or of any such other documents, provided that (i) no Lender will be liable for any of the foregoing to the extent any of the foregoing is found in a final non-appealable judgment by a court of competent jurisdiction to have resulted from the gross negligence or willful misconduct of the Administrative Agent and (ii) any indemnification required pursuant to Section 3.3(iv) will,

notwithstanding the provisions of this Section 13.7, be paid by the relevant Lender in accordance with the provisions thereof. The obligations of the Lenders under this Section 13.7 will survive payment of the Obligations and termination of this Agreement.

13.8. Notice of Default. The Administrative Agent will not be deemed to have knowledge or notice of the occurrence of any Default under this Agreement unless the Administrative Agent has received written notice from a Lender or the Borrowers referring to this Agreement describing such Default and stating that such notice is a "notice of default." In the event that the Administrative Agent receives such a notice, the Administrative Agent will give prompt notice thereof to the Lenders.

13.9. Rights as a Lender. In the event the Administrative Agent is a Lender, the Administrative Agent will have the same rights and powers hereunder and under any other Loan Document with respect to its Commitment and its Loans as any Lender and may exercise the same as though it were not the Administrative Agent, and the term "Lender" or "Lenders" will, at any time when the Administrative Agent is a Lender, unless the context otherwise indicates, include the Administrative Agent in its individual capacity. The Administrative Agent and its Affiliates may accept deposits from, lend money to, and generally engage in any kind of trust, debt, equity or other transaction, in addition to those contemplated by this Agreement or any other Loan Document, with the Credit Parties or any of their Subsidiaries in which the Credit Parties or such Subsidiary is not restricted hereby from engaging with any other Person.

13.10. Lender Credit Decision. Each Lender acknowledges that it has, independently and without reliance upon the Administrative Agent, the Syndication Agent or any other Lender and based on the financial statements prepared by the Credit Parties and such other documents

and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement and the other Loan Documents. Each Lender also acknowledges that it will, independently and without reliance upon the Administrative Agent, the Syndication Agent or any other Lender and based on such documents and information as it deems appropriate at the time, continue to make its own credit decisions in taking or not taking action under this Agreement and the other Loan Documents.

13.11. Successor Administrative Agent. The Administrative Agent may resign at any time by giving written notice thereof to the Lenders and Unit, such resignation to be effective upon the appointment of a successor Administrative Agent or, if no successor Administrative Agent has been appointed, 45 days after the retiring Administrative Agent gives notice of its intention to resign. The Administrative Agent may be removed at any time with or without cause by written notice received by the Administrative Agent from the Required Lenders, such removal to be effective on the date specified by the Required Lenders. Upon any such resignation or removal, the Required Lenders will have the right to appoint, on behalf of the Credit Parties and the Lenders, a successor Administrative Agent. If no successor Administrative Agent will have been so appointed by the Required Lenders within thirty days after the resigning Administrative Agent's giving notice of its intention to resign, then the resigning Administrative Agent may appoint, on behalf of the Credit Parties and the Lenders, a successor Administrative Agent. Notwithstanding the previous sentence, the Administrative Agent may at any time without the consent of the Credit Parties or any Lender, appoint any of its Affiliates which is a commercial bank as a successor Administrative Agent hereunder. If the Administrative Agent has resigned or been removed and no successor Administrative Agent has been appointed, the Lenders may perform all the duties of the Administrative Agent hereunder and the Borrowers will make all payments in respect of the Obligations to the applicable Lender and for all other purposes will deal directly with the Lenders. No successor Administrative Agent will be deemed to be appointed hereunder until such successor Administrative Agent has accepted the appointment. Any such successor Administrative Agent will be a commercial bank having capital and retained earnings of at least $100,000,000. Upon the acceptance of any appointment as Administrative Agent hereunder by a successor Administrative Agent, such successor Administrative Agent will thereupon succeed to and become vested with all the rights, powers, privileges and duties of the resigning or removed Administrative Agent. Upon the effectiveness of the resignation or removal of the Administrative Agent, the resigning or removed Administrative Agent will be discharged from its duties and obligations hereunder and under the Loan Documents. After the effectiveness of the resignation or removal of an Administrative Agent, the provisions of this Article XIII will continue in effect for the benefit of such Administrative Agent in respect of any actions taken or omitted to be taken by it while it was acting as the Administrative Agent hereunder and under the other Loan Documents.

13.12. Execution of Collateral Documents. The Lenders hereby empower and authorize the Administrative Agent to execute and deliver to Unit on their behalf the Security Agreement and all related agreements, documents or instruments as will be necessary or appropriate to effect the purposes of the Security Agreement.

13.13. Collateral Releases. The Lenders hereby empower and authorize the Administrative Agent to execute and deliver to Unit on their behalf any agreements, documents

or instruments as will be necessary or appropriate to effect any releases of Collateral which will be permitted by the terms hereof or of any other Loan Document or which will otherwise have been approved by the Required Lenders (or, if required by the terms of Section 11.2, all of the Lenders) in writing.

13.14. Syndication Agent. No Lender identified in this Agreement as the Syndication Agent will have any right, power, obligation, liability, responsibility or duty under this Agreement other than those applicable to all Lenders as such. Without limiting the foregoing, no Lender will have or be deemed to have a fiduciary relationship with any other Lender. Each Lender hereby makes the same acknowledgments with respect to such Lenders as it makes with respect to the Administrative Agent in Section 13.10.

13.15 Delegation to Affiliates. The Credit Parties and the Lenders agree that the Administrative Agent may delegate any of its duties under this Agreement to any of its Affiliates. Any Affiliate of the Administrative Agent which performs duties in connection with this Agreement will be entitled to the same benefits of the indemnification, waiver and other protective provisions to which the Administrative Agent is entitled under Articles XII and XIII.

ARTICLE XIV

BENEFIT OF AGREEMENT; ASSIGNMENTS; PARTICIPATIONS

14.1. Successors and Assigns. The terms and provisions of the Loan Documents will be binding upon and inure to the benefit of the Credit Parties and the Lenders and their respective successors and assigns permitted hereby, except that (i) the Credit Parties will not have the right to assign their rights or obligations under the Loan Documents without the prior written consent of each Lender, (ii) any assignment by any Lender must be made in compliance with Section 14.3, and (iii) any transfer by participation must be made in compliance with Section 14.2. Any attempted assignment or transfer by any party not made in compliance with this Section 14.1 will be null and void, unless such attempted assignment or transfer is treated as a participation in accordance with Section 14.3.2. The parties to this Agreement acknowledge that clause (ii) of this Section 14.1 relates only to absolute assignments and this Section 14.1 does not prohibit assignments creating security interests, including, without limitation, any pledge or assignment by any Lender of all or any portion of its rights under this Agreement and any Note to a Federal Reserve Bank; provided, however, that no such pledge or assignment creating a security interest will release the transferor Lender from its obligations hereunder unless and until the parties thereto have complied with the provisions of Section 14.3. The Administrative Agent may treat the Person which made any Loan or which holds any Note as the owner thereof for all purposes hereof unless and until such Person complies with Section 14.3; provided, however, that the Administrative Agent may in its discretion (but will not be required to) follow instructions from the Person which made any Loan or which holds any Note to direct payments relating to such Loan or Note to another Person. Any assignee of the rights to any Loan or any Note agrees by acceptance of such assignment to be bound by all the terms and provisions of the Loan Documents. Any request, authority or consent of any Person, who at the time of making such request or giving such authority or consent is the owner of the rights to any Loan (whether or not a Note has been issued in evidence thereof), will be conclusive and binding

on any subsequent holder or assignee of the rights to such Loan.

14.2. Participations.

14.2.1. Permitted Participants; Effect. Any Lender may, in the ordinary course of its business and in accordance with applicable law, at any time upon obtaining the prior written consent of Unit and the Required

Lenders, sell to one or more banks or other entities ("Participants") participating interests in any Outstanding Credit Exposure of such Lender, any Note held by such Lender, any Commitment of such Lender or any other interest of such Lender under the Loan Documents. In the event of any such sale by a Lender of participating interests to a Participant, such Lender's obligations under the Loan Documents will remain unchanged, such Lender will remain solely responsible to the other parties hereto for the performance of such obligations, such Lender will remain the owner of its Outstanding Credit Exposure and the holder of any Note issued to it in evidence thereof for all purposes under the Loan Documents, all amounts payable by the Borrowers under this Agreement will be determined as if such Lender had not sold such participating interests, and the Borrowers and the Administrative Agent will continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under the Loan Documents.

14.2.2. Voting Rights. Each Lender will retain the sole right to approve, without the consent of any Participant, any amendment, modification or waiver of any provision of the Loan Documents other than any amendment, modification or waiver with respect to any Credit Extension or Commitment in which such Participant has an interest which would require consent of all of the Lenders pursuant to the terms of Section 11.2 or of any other Loan Document.

14.2.3. Benefit of Certain Provisions. The Borrowers agree that each Participant will be deemed to have the right of setoff provided in Section 6.11 in respect of its participating interest in amounts owing under the Loan Documents to the same extent as if the amount of its participating interest were owing directly to it as a Lender under the Loan Documents, provided that each Lender will retain the right of setoff provided in Section 6.11 with respect to the amount of participating interests sold to each Participant. The Lenders agree to share with each Participant, and each Participant, by exercising the right of setoff provided in Section 6.11, agrees to share with each Lender, any amount received pursuant to the exercise of its right of setoff, such amounts to be shared in accordance with Section 6.11(c) as if each Participant were a Lender. The Borrowers further agree that each Participant will be entitled to the benefits of Sections 3.1, 3.2, 3.4 and 3.5 to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to Section 14.3, provided that (i) a Participant will not be entitled to receive any greater payment under Section 3.1, 3.2 or 3.5 than the Lender who sold the participating interest to such Participant would have received had it retained such interest for its own account, unless the sale of such interest to such Participant is made with the prior written consent of the Borrowers, and (ii) any Participant not incorporated under the laws of the United States of America or any State thereof agrees to comply with the provisions of Section 3.3 to the same extent as if it were a Lender.

14.3. Assignments.

14.3.1. Permitted Assignments. Any Lender may, in the ordinary course of its business and in accordance with applicable law, at any time assign to one or more banks or other entities ("Purchasers") all or any part of its rights and obligations under the Loan Documents. Such assignment will be substantially in the form of Exhibit C or in such other form as may be agreed to by the parties thereto. The consent of Unit, the Administrative Agent and the LC Issuer will be required prior to an assignment becoming effective with respect to a Purchaser which is not a Lender or an Affiliate thereof; provided, however, that if a Default has occurred and is continuing, the consent of the Credit Parties will not be required. Such consent of the Credit Parties will not be unreasonably withheld or delayed. Each such assignment with respect to a Purchaser which is not a Lender or an Affiliate thereof will (unless each of the Credit Parties and the Administrative Agent otherwise consent) be in an amount not less than the lesser of (i) $10,000,000 or (ii) the remaining amount of the assigning Lender's Commitment (calculated as at the date of such assignment) or outstanding Loans (if the applicable Commitment has been terminated).

14.3.2. Effect; Effective Date. Upon (i) delivery to the Administrative Agent of a notice of assignment, substantially in the form attached as Exhibit I to Exhibit C (a "Notice of Assignment"), together with any consents required by Section 14.3.1, and (ii) payment of a $500 fee to the Administrative Agent for processing such assignment, such assignment will become effective on the effective date specified in such Notice of Assignment. The Notice of Assignment will contain a representation by the Purchaser to the effect that none of the

consideration used to make the purchase of the Commitment and Outstanding Credit Exposure under the applicable assignment agreement are "plan assets" as defined under ERISA and that the rights and interests of the Purchaser in and under the Loan Documents will not be "plan assets" under ERISA. On and after the effective date of such assignment, such Purchaser will for all purposes be a Lender to this Agreement and any other Loan Document executed by or on behalf of the Lenders and will have all the rights and obligations of a Lender under the Loan Documents, to the same extent as if it were an original party hereto, and no further consent or action by the Credit Parties, the Lenders or the Administrative Agent will be required to release the transferor Lender with respect to the percentage of the Aggregate Commitment and Outstanding Credit Exposure assigned to such Purchaser. Upon the consummation of any assignment to a Purchaser pursuant to this Section 14.3.2, the transferor Lender, the Administrative Agent and the Borrowers will, if the transferor Lender or the Purchaser desires that its Loans be evidenced by Notes, make appropriate arrangements so that new Notes or, as appropriate, replacement Notes are issued to such transferor Lender and new Notes or, as appropriate, replacement Notes, are issued to such Purchaser, in each case in principal amounts reflecting their respective Commitments, as adjusted pursuant to such assignment.

14.3.3. Register. The Administrative Agent, acting solely for this purpose as an Administrative Agent of the Borrowers, will maintain at its main banking offices in

Tulsa, Oklahoma, a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitments of, and principal amounts of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register will be conclusive, and the Borrowers, the Administrative Agent and the Lenders may treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement, notwithstanding notice to the contrary. The Register will be available for inspection by the Borrowers and any Lender, at any reasonable time and from time to time upon reasonable prior notice.

14.4. Dissemination of Information. The Credit Parties authorize each Lender to disclose to any Participant or Purchaser or any other Person acquiring an interest in the Loan Documents by operation of law (each a "Transferee") and any prospective Transferee any and all information in such Lender's possession concerning the creditworthiness of the Credit Parties and their Subsidiaries, including without limitation any information contained in any reports provided to Administrative Agent; provided that each Transferee and prospective Transferee agrees to be bound by this Agreement.

14.5. Tax Treatment. If any interest in any Loan Document is transferred to any Transferee which is not incorporated under the laws of the United States or any State thereof, the transferor Lender will cause such Transferee, concurrently with the effectiveness of such transfer, to comply with the provisions of Section 3.3(iv).

14.6. Procedure for Increases and Addition of New Lenders. This Agreement permits increases in existing Lenders' Commitments without the consent or approval of the other Lenders, provided that the resulting Aggregate Commitments do not exceed the Maximum Credit Amount. This Agreement also permits the admission of new Lenders providing new Commitments, subject to the consent of the Lenders. Any amendment hereto for an increase in a Lender's Commitment or addition of a new Lender will be in the form attached hereto as Exhibit D. Only the written consent of the Administrative Agent, Unit and the existing Lender(s) increasing its or their Commitment(s) will be required to Exhibit D if and to the extent the Aggregate Commitments, as increased, will not exceed the Maximum Credit Amount. In addition, within a reasonable time after the effective date of any increase, the Administrative Agent will, and is hereby authorized and directed to, revise the Lenders Schedule reflecting such increase and will distribute revised Lenders Schedule to each of the Lenders and Unit, and the revised Lenders Schedule will replace the old Lenders Schedule and become part of this Agreement. On the Business Day following any increase, all outstanding Alternate Base Rate Advances will be reallocated among the Lenders (including any newly added Lenders) in accordance with the Lenders' respective revised Pro Rata Shares. Eurodollar Advances will not be reallocated among the Lenders prior to the expiration of the applicable Interest Period in effect at the time of any increase.

ARTICLE XV

NOTICES/CONSENTS

15.1. Notices. Except as otherwise permitted by Section 2.9 with respect to Borrowing Notices, all notices, requests and other communications to any party hereunder will be in writing (including facsimile transmission or similar writing) and will be given to such party: (x) in the case of the Borrowers or the Administrative Agent, at its address or facsimile number set forth on the signature pages hereof, (y) in the case of any Lender, at its address or facsimile number set forth on the Lenders Schedule or (z) in the case of any party, at such other address or facsimile number as such party may hereafter specify for the purpose by notice to the Administrative Agent and the Borrowers in accordance with the provisions of this Section 15.1. Each such notice, request or other communication will be effective (i) if given by facsimile transmission, when transmitted to the facsimile number specified in this Section and confirmation of receipt is received, (ii) if given by mail, 72 hours after such communication is deposited in the mails with first class postage prepaid, addressed as aforesaid, or (iii) if given by any other means, when delivered at the address specified in this Section; provided that notices to the Administrative Agent under Article II will not be effective until received.

15.2. Change of Address. The Borrowers, the Administrative Agent and any Lender (i) may each change the address for service of notice upon it by a notice in writing to the other parties hereto and (ii) will give such a notice if its address will change.

15.3. Consent to Amendments. This Agreement and any of the other Loan Documents may be amended, and the Borrowers may take any action herein prohibited, or omit to perform any act herein required to be performed by it, if the Borrowers will obtain the written consent to such amendment, action or omission to act, of the Administrative Agent and the Lenders. Each holder of any of the Notes at the time or thereafter outstanding will be bound by any consent authorized by this Section 15.3, whether or not the Notes will have been marked to indicate such consent, but any Notes issued thereafter may bear a notation referring to any such consent. No course of dealing between the Credit Parties and any holder of any of the Notes nor any delay in exercising any rights hereunder or under the Notes will operate as a waiver of any rights of any holder of any of the Notes. As used herein and in the Notes, the term "this Agreement" and references thereto will mean this Agreement as it may from time to time be amended, modified or supplemented.

15.4. USA PATRIOT Act Notice. IMPORTANT INFORMATION ABOUT PROCEDURES FOR OPENING A NEW ACCOUNT. To help the government fight the funding of terrorism and money laundering activities, federal law requires all financial institutions to obtain, verify, and record information that identifies each person or entity that opens an account, including any deposit account, treasury management account, loan, other extension of credit, or other financial services product. What this means for borrowers: When a borrower opens an account, the Bank will ask for the borrower's name, residential address, tax identification number, and other information that will allow the Bank to identify the borrower, including the borrower's date of birth if the borrower is an individual. The Bank may also ask, if the borrower is an individual, to see the borrower's driver's license or other identifying

documents, and, if the borrower is not an individual, to see the borrower's legal organizational documents or other identifying documents. The Bank will verify and record the information the Bank obtains from the borrower pursuant to the USA PATRIOT Act, and will maintain and retain that record in accordance with the regulations promulgated under the USA PATRIOT Act.

ARTICLE XVI

COUNTERPARTS

This Agreement may be executed in any number of counterparts, all of which taken together will constitute one agreement, and any of the parties hereto may execute this Agreement by signing any such counterpart. This Agreement will be effective when it has been executed by the Borrowers, the Administrative Agent, the LC Issuer and the Lenders and each party has notified the Administrative Agent by facsimile transmission or electronic transmission (e-mail) that it has taken such action. All closing documents will be furnished to the Administrative Agent with sufficient counterparts so that the Administrative Agent may furnish

one to each of the Lenders.

ARTICLE XVII

CHOICE OF LAW; CONSENT TO JURISDICTION; WAIVER OF JURY TRIAL

17.1. CHOICE OF LAW. THE LOAN DOCUMENTS (OTHER THAN THOSE CONTAINING A CONTRARY EXPRESS CHOICE OF LAW PROVISION) WILL BE CONSTRUED IN ACCORDANCE WITH THE INTERNAL LAWS OF THE STATE OF OKLAHOMA, BUT GIVING EFFECT TO FEDERAL LAWS APPLICABLE TO NATIONAL BANKS AND WILL BE DEEMED TO HAVE BEEN MADE OR INCURRED UNDER THE LAWS OF THE STATE OF OKLAHOMA EXCEPT ONLY WHERE THE APPLICABLE REMEDIAL OR PROCEDURAL LAWS OF OTHER JURISDICTIONS IN WHICH PORTIONS OF THE COLLATERAL ARE SITUATED ARE APPLICABLE THERETO.

17.2. CONSENT TO JURISDICTION. THE BORROWERS, THE ADMINISTRATIVE AGENT AND LENDERS HEREBY IRREVOCABLY SUBMIT TO THE NON-EXCLUSIVE JURISDICTION OF ANY UNITED STATES FEDERAL OR OKLAHOMA STATE COURT SITTING IN TULSA, OKLAHOMA IN ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO ANY LOAN DOCUMENTS AND THE BORROWERS, THE ADMINISTRATIVE AGENT AND LENDERS HEREBY IRREVOCABLY AGREES THAT ALL CLAIMS IN RESPECT OF SUCH ACTION OR PROCEEDING MAY BE HEARD AND DETERMINED IN ANY SUCH COURT AND IRREVOCABLY WAIVES ANY OBJECTION IT MAY NOW OR HEREAFTER HAVE AS TO THE VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING BROUGHT IN SUCH A COURT OR THAT SUCH COURT IS AN INCONVENIENT FORUM. NOTHING HEREIN WILL LIMIT THE RIGHT OF THE ADMINISTRATIVE AGENT, THE LC ISSUER OR ANY LENDER TO BRING PROCEEDINGS AGAINST THE BORROWERS IN THE COURTS OF ANY OTHER JURISDICTION.

17.3. NO ORAL AGREEMENTS. THE LOAN DOCUMENTS EMBODY THE ENTIRE AGREEMENT AND UNDERSTANDING BETWEEN THE PARTIES AND SUPERSEDE ALL OTHER AGREEMENTS AND UNDERSTANDINGS BETWEEN SUCH PARTIES RELATING TO THE SUBJECT MATTER HEREOF AND THEREOF, THE LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

17.4. EXCULPATION PROVISIONS. EACH OF THE PARTIES HERETO SPECIFICALLY AGREES THAT IT HAS A DUTY TO READ THIS AGREEMENT, THE NOTES AND THE COLLATERAL DOCUMENTS AND AGREES THAT IT IS CHARGED WITH NOTICE AND KNOWLEDGE OF THE TERMS OF THIS AGREEMENT, THE NOTES AND THE COLLATERAL DOCUMENTS; THAT IT HAS IN FACT READ THIS AGREEMENT AND IS FULLY INFORMED AND HAS FULL NOTICE AND KNOWLEDGE OF THE TERMS, CONDITIONS AND EFFECTS OF THIS AGREEMENT; THAT IT HAS BEEN REPRESENTED BY INDEPENDENT LEGAL COUNSEL OF ITS CHOICE THROUGHOUT THE NEGOTIATIONS PRECEDING ITS EXECUTION OF THIS AGREEMENT, THE NOTES AND THE COLLATERAL DOCUMENTS; AND HAS RECEIVED THE ADVICE OF ITS ATTORNEY IN ENTERING INTO THIS AGREEMENT, THE NOTES AND THE COLLATERAL DOCUMENTS; AND THAT IT RECOGNIZES THAT CERTAIN OF THE TERMS OF THIS AGREEMENT, THE NOTES AND THE COLLATERAL DOCUMENTS RESULT IN ONE PARTY ASSUMING THE LIABILITY INHERENT IN SOME ASPECTS OF THE TRANSACTION AND RELIEVING THE OTHER PARTY OF ITS RESPONSIBILITY FOR SUCH LIABILITY. EACH PARTY HERETO AGREES AND COVENANTS THAT IT WILL NOT CONTEST THE VALIDITY OR ENFORCEABILITY OF ANY EXCULPATORY PROVISION OF THIS AGREEMENT AND THE COLLATERAL DOCUMENTS ON THE BASIS THAT THE PARTY HAD NO NOTICE OR KNOWLEDGE OF SUCH PROVISION OR THAT THE PROVISION IS NOT "CONSPICUOUS."

17.5. WAIVER OF JURY TRIAL, PUNITIVE DAMAGES. THE BORROWERS, THE ADMINISTRATIVE AGENT, THE LC ISSUER AND EACH LENDER HEREBY WAIVE TRIAL BY JURY IN ANY JUDICIAL PROCEEDING INVOLVING, DIRECTLY OR INDIRECTLY, ANY MANNER (WHETHER SOUNDING IN TORT, CONTRACT OR OTHERWISE) IN ANY WAY ARISING OUT OF, RELATED TO OR CONNECTED WITH ANY LOAN DOCUMENT OR THE RELATIONSHIP ESTABLISHED THEREUNDER. EACH BORROWER AND EACH LENDER HEREBY FURTHER (A) IRREVOCABLY WAIVE, TO THE MAXIMUM EXTENT NOT PROHIBITED BY LAW, ANY RIGHT IT MAY HAVE TO CLAIM OR RECOVER IN ANY SUCH LITIGATION ANY "SPECIAL DAMAGES," AS DEFINED BELOW, (B) CERTIFY THAT NO PARTY HERETO NOR ANY REPRESENTATIVE OR AGENT OR COUNSEL FOR ANY PARTY HERETO HAS REPRESENTED, EXPRESSLY OR OTHERWISE, OR IMPLIED THAT SUCH PARTY WOULD NOT, IN THE EVENT OF

LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVERS, AND (C) ACKNOWLEDGE THAT IT HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT, THE OTHER LOAN DOCUMENTS AND THE TRANSACTIONS CONTEMPLATED HEREBY AND THEREBY BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS CONTAINED IN THIS SECTION. AS USED IN THIS SECTION, "SPECIAL DAMAGES" INCLUDES ALL SPECIAL, CONSEQUENTIAL, EXEMPLARY, OR PUNITIVE DAMAGES (REGARDLESS OF HOW NAMED), BUT DOES NOT INCLUDE ANY PAYMENTS OR FUNDS WHICH

ANY PARTY HERETO HAS EXPRESSLY PROMISED TO PAY OR DELIVER TO
ANY OTHER PARTY HERETO.

IN WITNESS WHEREOF, the Borrowers, the Lenders and the Administrative Agent have executed this Agreement as of the date first above written.

UNIT CORPORATION, a Delaware corporation
MOUNTAIN FRONT PIPELINE COMPANY,
INC., an Oklahoma corporation
UNIT PETROLEUM COMPANY,
an Oklahoma corporation
UNIT DRILLING COMPANY,
an Oklahoma corporation
PETROLEUM SUPPLY COMPANY,
an Oklahoma corporation,
SERDRILCO, INC.
an Oklahoma corporation and
UNIT ENERGY CANADA INC.,
an Alberta, Canada corporation

By_____
Larry D. Pinkston
President
UNIT CORPORATION,
MOUNTAIN FRONT PIPELINE
COMPANY, INC.,
UNIT PETROLEUM COMPANY,
UNIT DRILLING COMPANY,
PETROLEUM SUPPLY COMPANY,
SERDRILCO, INC. and
UNIT ENERGY CANADA INC.

7130 South Lewis Avenue, Suite 1000
Tulsa, Oklahoma 74136
Attention: Larry Pinkston
Telephone: (918) 493-7700
Facsimile: (918) 493-7711

BANK OF OKLAHOMA, NATIONAL
ASSOCIATION, Individually, as LC Issuer
and as Administrative Agent

By_____
Pam Schloeder
Senior Vice President

101 East Second Street
Bank of Oklahoma Tower
One Williams Center
Tulsa, Oklahoma 74192
Telephone: (918) 588-6012
Facsimile: (918) 588-6880

BANK OF AMERICA, N.A., a Lender

By_____
Michael D. Earl
Senior Vice President

515 South Boulder
Tulsa, Oklahoma, 74119
Telephone: (918) 591-8532
Facsimile: (918) 591-8472

BMO NESBITT BURNS FINANCING, INC., a Lender

By_____
James Ducote, Vice President

115 South LaSalle Street
11th Floor West
Chicago, ILL60603
Telephone: (312) 461-5594
Facsimile: (312) 750-3456

(with a copy to)

Bank of Montreal
Houston Agency
700 Louisiana Street
4400 Bank of America Center
Houston, Texas 77002
Telephone: (713) 546-9760
Facsimile: (713) 223-4007

COMPASS BANK, a Lender

By_____
Kathleen J. Bowen
Vice President

24 Greenway Plaza
14th Floor
Houston, Texas 77046
Telephone: (713) 968-8273
Facsimile: (713) 968-8292

EXHIBIT A

FORM OF PROMISSORY NOTE

EXHIBIT B

COMPLIANCE CERTIFICATE

Bank of Oklahoma, National Association, as
Administrative Agent
Bank of Oklahoma Tower

One Williams Center
Tulsa, Oklahoma 74192

This Compliance Certificate is delivered pursuant to Section 6.1(iii) of that certain Credit Agreement, dated as of January 30, 2004 (as amended, modified, supplemented or restated from time to time, the "Credit Agreement"), by and among Unit Corporation, a Delaware corporation ("Unit") ("Unit" and the subsidiaries thereof signatory parties to the Credit Agreement, as borrowers, collectively the "Borrowers"), the Lenders (as therein defined), and Bank of Oklahoma, National Association, as Administrative Agent for the Lenders. Capitalized terms used herein and not otherwise defined have the respective meanings assigned to them in the Credit Agreement.

As used in this Compliance Certificate (including the Schedules attached hereto), "Quarterly Calculation Date" means the last day of the fiscal quarter ending _____, 200_.

The undersigned hereby certifies, represents and warrants as follows:

1. The undersigned is the chief financial officer of Unit and as such he or she is authorized to execute and deliver this Compliance Certificate on behalf of the Borrowers and their Subsidiaries (collectively, the "Credit Parties").

2. The undersigned has reviewed the activities of the Credit Parties with a view to determining whether the Credit Parties have fulfilled their respective obligations under the Loan Documents.

3. Except as set forth on Schedule I attached hereto, to the best knowledge of the undersigned, after due inquiry:

(a) each of the Credit Parties has complied with and is in compliance with all of the terms and provisions of each of the Loan Documents to which it is a party;

(b) all representations and warranties made by the Borrowers in the Credit Agreement are true and correct in all material respects as of the date hereof (other than representations and warranties which refer solely to an earlier specified date); and

(c) no Default has occurred and is continuing under the Credit Agreement.

4. As of the Quarterly Calculation Date, the Borrower was in compliance with the financial covenants set forth in Sections 8.1, 8.2 and 8.3 of the Credit Agreement, as demonstrated by the computations set forth in Schedule II attached hereto, calculated in accordance with GAAP.

5. Schedule III attached hereto contains a complete and accurate list of all Material Subsidiaries of the Borrowers. The Borrowers have complied with Section 9.4 of the Credit Agreement by causing each of the Material Subsidiaries to become a party to the Subsidiary Guaranty.

IN WITNESS WHEREOF, I have executed this Certificate this _____ day of _____, 2004.

_____
_____(name)
Chief Financial Officer
Unit Corporation

SCHEDULE I
To Compliance Certificate

(Disclosure of Defaults and Non-Compliance)

A. Nature of Default or terms of Loan Documents that have not been complied with in all material respects:

B. Steps being taken to correct such Default or noncompliance:

SCHEDULE II
To Compliance Certificate

(Financial Covenant Calculations)

1. Calculation of Current Ratio (Section 8.1)

(To be calculated on a consolidated basis for Unit as of the Quarterly Calculation Date)

Current Assets (including Available Aggregate Commitment)	$_____
Divided by: Current Liabilities	/_____
Consolidated Current Ratio: =	=_____
	(must be equal to or greater than 1.0 to 1.0)

2. Consolidated Long Term Debt-to-EBITDA Ratio (Section 8.2)

(To be calculated on a consolidated basis for Unit as of the Quarterly Calculation Date)

A. Consolidated Long Term Debt	$_____
B. Consolidated EBITDA	$_____
C. Consolidated Long Term Debt to EBITDA Ratio (Ratio of Item A to Item B)	_____ to 1.00
	(Must not be greater than 3.25 to 1.00)

3. Calculation of Consolidated Minimum Net Worth (Section 8.3)

(To be calculated for Unit as of the Quarterly Calculation Date)

Consolidated Net Worth:	$_____
	(must be equal to or greater than $350,000,000)

SCHEDULE III
To Compliance Certificate

(Material Subsidiaries)

As of the Quarterly Calculation Date, the following constituted all of the Material Subsidiaries of the Borrowers:

EXHIBIT C

FORM OF ASSIGNMENT

This Assignment and Assumption (the "Assignment and Assumption") is dated as of the Effective Date set forth below and is entered into by and between [Insert name of Assignor] (the "Assignor") and [Insert name of Assignee] (the "Assignee"). Capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement identified below (as amended, the "Credit Agreement"), receipt of a copy of which is hereby acknowledged by the Assignee. The Terms and Conditions set forth in Annex 1 attached hereto are hereby agreed to and incorporated herein by reference and made a part of this Assignment and Assumption as if set forth herein in full.

The Assignor hereby sells and assigns to the Assignee, and the Assignee hereby purchases and assumes from the Assignor, an interest in and to the Assignor's rights and obligations under the Credit Agreement and the other Loan Documents, such that after giving effect to such assignment the Assignee shall have purchased pursuant to this Assignment Agreement the percentage interest specified in Item 6(a) below of all outstanding rights and obligations under the Credit Agreement and the other Loan Documents relating to the credit facility listed in Item 5 below (the "Assigned Interest"). The aggregate Commitment (including LC Obligations, if the applicable Commitment has been terminated) purchased by the Assignee hereunder is set forth in Item 6 below.

In consideration for the sale and assignment of Commitments hereunder, the Assignee shall pay the Assignor, on the Effective Date, the amount agreed to by the Assignor and the Assignee. On and after the Effective Date, the Assignee shall be entitled to receive all payments of principal, interest, reimbursement obligations and fees with respect to the interest assigned hereby. The Assignee will promptly remit to the Assignor any interest on Loans and fees received from the Administrative Agent which relate to the portion of the Loans or LC Obligations assigned to the Assignee hereunder and not previously paid by the Assignee to the Assignor. In the event that either party hereto receives any payment to which the other party hereto is entitled under this Assignment Agreement, then the party receiving such amount shall promptly remit it to the other party hereto.

1. Assignor: _____

2. Assignee: _____ [and is an Affiliate of _____[identify Lender](1)

3. Borrowers: Unit Corporation, Mountain Front Pipeline Company, Inc., Unit Drilling Company, Unit Petroleum Company, Petroleum Supply Company, Serdrilco, Inc. and Unit Energy Canada, Inc.

_____
(1) Select as applicable.

4. Administrative Agent: Bank of Oklahoma, National Association, as Administrative Agent under the Credit Agreement.

5. Credit Agreement: The $150,000,000 Credit Agreement dated as of January 30, 2004 among Borrowers, Bank of Oklahoma, National Association, as Administrative Agent, and the Lenders signatory parties thereto.

6. Assigned Interest: _____

a. Assignee's percentage interest of credit facility purchased under the Assignment Agreement _____%

b. Amount of credit facility purchased under the Assignment Agreement

$_____

c. Assignee's Loans (or LC Obligations with respect to terminated Commitments) purchased hereunder: $_____

7. Trade Date: _____(2)

8. Payment Instructions to Assignor:

Effective Date: _____, 200__ [TO BE INSERTED BY ADMINISTRATIVE AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER BY THE ADMINISTRATIVE AGENT.]

_____

(2) Insert if satisfaction of minimum amounts is to be determined as of the Trade Date.

The terms set forth in this Assignment and Assumption are hereby agreed to:

ASSIGNOR

[name]

BY:_____
Title:_____

ASSIGNEE

[name]

BY:_____
Title:_____

Consented and Accepted:

BANK OF OKLAHOMA, N.A.
as Administrative Agent for the Lenders

By:_____
Name: _____
Title: _____

UNIT CORPORATION

By:_____
Name: _____
Title: _____

ANNEX 1
TERMS AND CONDITIONS FOR
ASSIGNMENT AND ASSUMPTION

1. Representations and Warranties.

1.1 Assignor. The Assignor represents and warrants that (i) it is the legal and beneficial owner of the Assigned Interest, (ii) the Assigned Interest is free and clear of any lien, encumbrance or other adverse claim and (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby. Neither the Assignor nor any of its officers, directors, employees, agents or attorneys shall be responsible for (i) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency, perfection, priority, collectibility, or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of the Borrowers, any of their Subsidiaries or Affiliates or any other Person obligated in respect of any Loan Document, (iv) the performance or observance by the Borrowers, any of their Subsidiaries or Affiliates or any other Person of any of their respective obligations under any Loan Document, (v) inspecting any of the property, books or records of the Borrowers, or Subsidiary Guarantor, or (vi) any mistake, error of judgment, or action taken or omitted to be taken in connection with the Loans or the Loan Documents.

1.2 Assignee. The Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of the Assigned Interest, shall have the obligations of a Lender thereunder, (iii) agrees that its payment instructions and notice instructions are as set forth in Item 8 above of this Assignment and Assumption, (iv) confirms that none of the funds, monies, assets or other consideration being used to make the purchase and assumption hereunder are "plan assets" as defined under ERISA and that its rights, benefits and interests in and under the Loan Documents will not be "plan assets" under ERISA, (v) agrees to indemnify and hold the Assignor harmless against all losses, costs and expenses (including, without limitation, reasonable attorneys' fees) and liabilities incurred by the Assignor in connection with or arising in any manner from the Assignee's non-performance of the obligations assumed under this Assignment and Assumption, (vi) it has received a copy of the Credit Agreement, together with copies of financialstatements and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Assignment and Assumption and to purchase the Assigned Interest on the basis of which it has made such analysis and decision independently and without reliance on the Administrative Agent or any other Lender, and (vii) attached as Schedule 1 to this Assignment and Assumption is any documentation required to be delivered by the Assignee with respect to its tax status

pursuant to the terms of the Credit Agreement, exemption from backup withholding (IRS From W-9 or successor form) on payments pursuant to the Credit Agreement or and other Loan Document described or defined therein or as a Lender that is not a United States person under Section 7701(a)(30) of the Internal Revenue Code for United States federal income tax purposes, duly completed and executed by the Assignee and (b) agrees that (i) it will, independently and without reliance on the Administrative Agent, the Assignor or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. Payments. The Assignee shall pay the Assignor, on the Effective Date, the amount agreed to by the Assignor and the Assignee. From and after the Effective Date, the Administrative Agent shall make all payments in respect of

the Assigned Interest (including payments of principal, interest, fees and other amounts) to the Assignor for amounts which have accrued to but excluding the Effective Date and to the Assignee for amounts which have accrued from and after the Effective Date.

3. General Provisions. This Assignment and Assumption shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Assignment and Assumption may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Assumption by telecopy shall be effective as delivery of a manually executed counterpart of this Assignment and Assumption. This Assignment and Assumption shall be governed by, and construed in accordance with, the laws of the State of Oklahoma.

SCHEDULE I

(Lender Tax Status Information)

EXHIBIT D

FORM OF AMENDMENT FOR AN INCREASED OR NEW COMMITMENT

This AMENDMENT is made as of the ___ day of _____, 200__, by and among Unit Corporation, a Delaware corporation (as agent for the "Borrowers" signatory parties to the Credit Agreement described and defined below, referred to herein as "Unit"), Bank of Oklahoma, N.A., as administrative agent for the Lenders signatory parties to the Credit Agreement (the "Administrative Agent"), and _____ (the "Supplemental Lender").

The Borrowers (including Unit), the Administrative Agent and certain other Lenders, as described therein, are parties to a Credit Agreement dated as of January 30, 2004 (as amended, modified, supplemented, or restated, collectively the "Credit Agreement"). All terms used herein and not otherwise defined shall have the same meaning given to them in the Credit Agreement.

Pursuant to Section 14.6 of the Credit Agreement, Unit, on behalf of the Borrowers, has the right to obtain additional Commitments upon satisfaction of certain conditions. This Amendment requires only the signature of Unit, the Administrative Agent and the Supplemental Lender so long as the aggregate amount of the commitments is not increased above the Maximum Credit Amount specified in the Credit Agreement.

The Supplemental Lender is either (a) an existing Lender which is increasing its Commitment or (b) a new Lender which is a lending institution whose identity the Administrative Agent will approve by its signature below.

In consideration of the foregoing, such Supplemental Lender, from and after the date hereof shall have a Commitment of $_____ and if it is a new Lender, the Supplemental Lender hereby assumes all of the rights and obligations of a Lender under the Credit Agreement.

The Borrowers have executed and delivered to the Supplemental Lender as of the date hereof, if requested by the Supplemental Lender, a new or amended and restated Note in the form attached to the Credit Agreement as Exhibit A to evidence the new or increased Commitment of the Supplemental Lender.

IN WITNESS WHEREOF, the Administrative Agent, the Borrower and the Supplemental Lender have executed this Amendment as of the date shown above.

UNIT CORPORATION

By:_____

Larry D. Pinkston,
President and Chief Financial Officer

[SUPPLEMENT LENDER]

By:_____
Name: _____
Title: _____

BANK OF OKLAHOMA, N.A.,
Administrative Agent for the Lenders

By:_____
Name: _____
Title: _____

EXHIBIT E

SUBSIDIARY GUARANTY

THIS GUARANTY AGREEMENT ("Guaranty") is made and entered into effective as of January 30, 2004, by the undersigned guarantor (the "Guarantor"), in favor of (i) the Lenders from time to time parties to the Credit Agreement described below and (ii) Bank of Oklahoma, National Association, as Administrative Agent under the Credit Agreement.

RECITALS

A. Unit Corporation, a Delaware corporation, Mountain Front Pipeline Company, Inc., Unit Drilling Company, an Oklahoma corporation, Unit Petroleum Company, Inc., an Oklahoma corporation, Petroleum Supply Company, an Oklahoma corporation, SerDrilco, Inc., an Oklahoma corporation, and Unit Energy Canada, Inc., an Alberta, Canada corporation (collectively, the "Borrowers"), the Lenders therein named, and Bank of Oklahoma, National Association, as Administrative Agent for the Lenders, are parties to that certain Credit Agreement dated effective as of even date herewith (as amended, modified, supplemented, restated and in effect from time to time, the "Credit Agreement").

B. Capitalized terms used herein and not otherwise defined herein have the respective meanings assigned to them in the Credit Agreement.

C. Pursuant to the Credit Agreement, the Lenders have severally agreed to establish in favor of the Borrowers certain Commitments for Advances and LC Obligations in the Aggregate Commitment Amounts, subject to the Maximum Credit Amount.

D. The Guarantor is a Material Subsidiary and will receive substantial and valuable consideration and benefit from the Commitments and the Loans advanced and the LCs issued from time to time by the Lenders and the LC Issuer, respectively, to the Borrowers pursuant to the Credit Agreement.

D. It is a condition precedent to the closing of the Credit Agreement and to each Extension of Credit thereunder that the Guarantor executes and delivers this Guaranty whereby the Guarantor shall absolutely and unconditionally guarantee the prompt and punctual payment when due of all of the Guaranteed Obligations (as hereinafter defined).

NOW, THEREFORE, in consideration of the credit to be extended pursuant to the Credit Agreement, and as a material inducement therefor, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby covenants and agrees as follows:

SECTION 1. Guaranty. Subject to Section 9 hereof, the Guarantor hereby guarantees to the Lenders and the Administrative Agent, absolutely, unconditionally and irrevocably, and without limitation as to amount, the prompt

performance and payment when due (whether at a

stated maturity or earlier by reason of acceleration or otherwise) of all Loans, LC Obligations, Reimbursement Obligations and all other Obligations and Outstanding Credit Exposure (as each such term is defined in the Credit Agreement), including, without limitation, principal, interest and fees, and all other liabilities and obligations now or hereafter owing by the Borrowers to the Lenders under the Credit Agreement, the Notes and other relevant Loan Documents, including, without limitation, indemnities, reasonable attorneys' fees, filing and recording costs, out-of- pocket expenses, collection costs and other amounts payable under the Loan Documents, including any such liabilities or obligations incurred or accrued during the pendency of any bankruptcy, insolvency, receivership or other similar proceeding, whether or not allowed or allowable in such proceeding (all of the foregoing liabilities and obligations being hereinafter collectively referred to as the "Guaranteed Obligations"). This Guaranty is a guaranty of payment and not just of collectibility and is in no way conditioned or contingent upon any attempt to collect from the Borrowers or upon any other event, contingency or circumstance whatsoever. If for any reason whatsoever the Borrowers shall fail or be unable duly, punctually and fully to pay such amounts as and when the same shall become due and payable, the Guarantor, without demand, presentment, protest or notice of any kind, will forthwith pay or cause to be paid such amounts to the Administrative Agent under the terms of the Credit Agreement, any Note or other relevant Loan Document, in lawful money of the United States, at the place specified in the Credit Agreement, or perform or comply with the same or cause the same to be performed or complied with, together with interest (to the extent provided for under the Credit Agreement) on any amount due and owing from the Borrowers. The Guarantor, promptly after demand, will pay to the Administrative Agent the reasonable costs and expenses of collecting such amounts or otherwise enforcing this Guaranty, including, without limitation, the reasonable fees and expenses of counsel. Notwithstanding the foregoing, the right of recovery against the Guarantor under this Guaranty is limited to the extent it is judicially determined with respect to any Guarantor that entering into this Guaranty would violate Section 548 of the United States Bankruptcy Code or any comparable provisions of any state law, in which case such Guarantor shall be liable under this Guaranty only for amounts aggregating up to the largest amount that would not render such Guarantor's obligations hereunder subject to avoidance under Section 548 of the United States Bankruptcy Code or any comparable provisions of any state law.

SECTION 2. Guarantor's Obligations Unconditional. The obligations of the Guarantor under this Guaranty shall be primary, absolute and unconditional obligations of the Guarantor, shall not be subject to any counterclaim, set-off, deduction, diminution, abatement, recoupment, suspension, deferment, reduction or defense based upon any claim the Guarantor or any other Person may have against the Borrowers or any other Person, and to the full extent permitted by applicable law shall remain in full force and effect without regard to, and shall not be released, discharged or in any way affected by, any circumstance or condition whatsoever (whether or not the Guarantor or the Borrowers shall have any knowledge or notice thereof), including:

(a) any termination, amendment or modification of or deletion from or addition or supplement to or other change in the Credit Agreement, the Loan Documents or any other instrument or agreement applicable to any of the parties to any of the Loan Documents;

(b) any furnishing or acceptance of any security, or any release of any security, for the Guaranteed Obligations, or the failure of any security or the failure of any Person to perfect any interest in any collateral;

(c) any failure, omission or delay on the part of the Borrowers to conform or comply with any term of any of the Loan Documents or any other instrument or agreement referred to in subsection (a) above, including, without limitation, failure to give notice to the Guarantor of the occurrence of a "Default" or an "Event of Default" under any Loan Document;

(d) any waiver of the payment, performance or observance of any of the obligations, conditions, covenants or agreements contained in any Loan Document, or any other waiver, consent, extension, indulgence, compromise, settlement, release or other action or inaction under or in respect of any of the Loan Documents or any other instrument or agreement referred to in subsection (a) above or any obligation or liability of the Borrowers, or

any exercise or non-exercise of any right, remedy, power or privilege under or in respect of any such instrument or agreement or any such obligation or liability;

(e) any failure, omission or delay on the part of any of the Administrative Agent or the Lenders to enforce, assert or exercise any right, power or remedy conferred on the Administrative Agent or the Lenders in this Guaranty, or any such failure, omission or delay on the part of the Administrative Agent or the Lenders in connection with any Loan Document, or any other action on the part of the Administrative Agent or the Lenders;

(f) any voluntary or involuntary bankruptcy, insolvency, reorganization, arrangement, readjustment, assignment for the benefit of creditors, composition, receivership, conservatorship, custodianship, liquidation, marshaling of assets and liabilities or similar proceedings with respect to the Borrowers, any Guarantor or any other Person or any of their respective properties or creditors, or any action taken by any trustee or receiver or by any court in any such proceeding;

(g) any discharge, termination, cancellation, frustration, irregularity, invalidity or unenforceability, in whole or in part, of any of the Loan Documents or any other agreement or instrument referred to in subsection (a) above or any term hereof;

(h) any merger or consolidation of the Borrowers or any Guarantor into or with any other corporation, or any sale, lease or transfer of any of the assets of the Borrowers or any Guarantor to any other Person;

(i) any change in the ownership of any shares of capital stock of the Borrowers or any change in the corporate relationship between the Borrowers and the Guarantor, or any termination of such relationship;

(j) any release or discharge, by operation of law, of the Guarantor from the performance or observance of any obligation, covenant or agreement contained in this Guaranty; or

(k) any other occurrence, circumstance, happening or event whatsoever, whether similar or dissimilar to the foregoing, whether foreseen or unforeseen, and any other circumstance which might otherwise constitute a legal or equitable defense or discharge of the liabilities of a guarantor or surety or which might otherwise limit recourse against the Guarantor.

SECTION 3. Full Recourse Obligations. The obligations of the Guarantor set forth herein constitute the full recourse obligations of the Guarantor enforceable against them to the full extent of all their assets and properties.

SECTION 4. Waiver. The Guarantor unconditionally waives, to the extent permitted by applicable law, (a) notice of any of the matters referred to in Section 2 hereof, (b) notice to the Guarantor of the incurrence of any of the Guaranteed Obligations, notice to the Guarantor or the Borrowers of any breach or default by the Borrowers or the Guarantor with respect to any of the Guaranteed Obligations or any other notice that may be required, by statute, rule of law or otherwise, to preserve any rights of the Administrative Agent or the Lenders against the Guarantor, (c) presentment to or demand of payment from the Borrowers or the Guarantors with respect to any amount due under any Loan Document or protest for nonpayment or dishonor, (d) any right to the enforcement, assertion or exercise by the Administrative Agent or the Lenders of any right, power, privilege or remedy conferred in the Credit Agreement or any other Loan Document or otherwise, (e) any requirement of diligence on the part of any of the Administrative Agent or the Lenders, (f) any requirement to exhaust any remedies or to mitigate the damages resulting from any default under any Loan Document, (g) any notice of any sale, transfer or other disposition by any of the Lenders of any right, title to or interest in the Credit Agreement or in any other Loan Document, and (h) any other circumstance whatsoever which might otherwise constitute a legal or equitable discharge, release or defense of a guarantor or surety or which might otherwise limit recourse against the Guarantor.

SECTION 5. Subrogation, Contribution, Reimbursement or Indemnity. Until one year and one day after all Guaranteed Obligations have been indefeasibly paid in full, the Guarantor agrees not to take any action pursuant to any rights which may have arisen in connection with this Guaranty to be subrogated to any of the rights (whether contractual, under the United States Bankruptcy Code, as amended, including Section 509 thereof, under common law or otherwise) of any of the Lenders against the Borrowers or against any collateral security or guaranty

or right of offset held by the Administrative Agent or the Lenders for the payment of the Guaranteed Obligations. Until one year and one day after all Guaranteed Obligations have been indefeasibly paid in full, the Guarantor agrees not to take any action pursuant to any contractual, common law, statutory or other rights of reimbursement, contribution, exoneration or indemnity (or any similar right) from or against the Borrowers which may have arisen in connection with this Guaranty. So long as the Guaranteed Obligations remain, if any amount shall be paid by or on behalf of the Borrowers to any Guarantor on account of any of the rights waived in this Section 5, such amount shall be held by such Guarantor in trust, segregated from other funds of such

Guarantor, and shall, forthwith upon receipt by such Guarantor, be turned over to the Administrative Agent (duly endorsed by such Guarantor to the Administrative Agent, if required), to be applied against the Guaranteed Obligations, whether matured or unmatured, in such order as the Administrative Agent may determine. The provisions of this Section 5 shall survive the term of this Guaranty and the payment in full of the Guaranteed Obligations.

SECTION 6. Effect of Bankruptcy or Insolvency Proceedings. This Guaranty shall continue to be effective or be automatically reinstated, as the case may be, if at any time payment, in whole or in part, of any of the sums due to any of the Lenders pursuant to the terms of the Credit Agreement or any other Loan Document is rescinded or must otherwise be restored or returned by such Bank upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of the Borrowers or any other Person, or upon or as a result of the appointment of a custodian, receiver, trustee or other officer with similar powers with respect to the Borrowers or other Person or any substantial part of its property, or otherwise, all as though such payment had not been made. If an event permitting the acceleration of the maturity of the principal amount of the Notes shall at any time have occurred and be continuing, and such acceleration shall at such time be prevented by reason of the pendency against the Borrowers or any other Person of a case or proceeding under a bankruptcy or insolvency law, the Guarantor agrees that, for purposes of this Guaranty and its obligations hereunder, the maturity of the principal amount of the Notes and all other Guaranteed Obligations shall be deemed to have been accelerated with the same effect as if the Lenders had accelerated the same in accordance with the terms of the Credit Agreement or other applicable Loan Document, and the Guarantor shall forthwith pay such principal amount and interest thereon and any other amounts guaranteed hereunder without further notice or demand.

SECTION 7. Termination. This Guaranty shall terminate when, and only when, all of the Guaranteed Obligations have been paid and performed in full, all in accordance with the provisions of the Credit Agreement.

SECTION 8. Representations and Warranties. Guarantor represents and warrants that:

(a) It (i) is duly organized, validly existing in good standing under the laws of the jurisdiction of its incorporation or organization, (ii) has the corporate or other necessary organizational power and authority, and the legal right to own and operate its Properties, to lease the Properties it operates as lessee and to conduct the business in which it is currently engaged, (iii) is duly qualified as a foreign entity and in good standing under the laws of each jurisdiction where its ownership, lease or operation of Property or the conduct of its business requires such qualification, other than in such jurisdictions where the failure to be so qualified and in good standing has not had and could not have a Material Adverse Effect, and (iv) is in compliance with all applicable law, except to the extent that the failure to comply therewith has not had and could not be reasonably expected to have a Material Adverse Effect.

(b) It has the power and authority and legal right to execute and deliver this Guaranty and to perform its obligations hereunder. The execution and delivery by it of this Guaranty and the performance of its obligations hereunder have been duly authorized

by proper proceedings. No consent or authorization of, filing with, notice to or other act by or in respect of, any Governmental Authority or other Person is required in connection with its execution and delivery of this Guaranty and performance of its obligations hereunder (other than those which have been obtained).

(c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor, enforceable against it in accordance with its terms, except as enforceability may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the enforcement of creditors' rights generally and by general equitable principles (whether enforcement is sought by proceedings in equity or at law).

(d) The execution, delivery and performance of this Guaranty will not violate any applicable law or any material agreement, instrument or undertaking to which any Guarantor is a party or by which it or any of its Property is bound (collectively, a "Contractual Obligation") of the Guarantor (except those as to which waivers or consents have been obtained and those which could not reasonably be expected to have a Material Adverse Effect), and will not result in, or require, the creation or imposition of any Lien on any of its Properties or revenues pursuant to any applicable law or Contractual Obligation.

(e) It has a substantial economic interest in the Borrowers and expects to derive benefits from transactions resulting in the creation of the Guaranteed Obligations hereby. The Administrative Agent and the Lenders may rely conclusively on a continuing warranty hereby made, that each Guarantor continues to be benefited by the Lenders' extension of credit to the Borrowers, and neither the Administrative Agent nor the Lenders shall have any duty to inquire into or confirm the receipt of any such benefits, and this Guaranty shall be effective and enforceable by the Administrative Agent and the Lenders without regard to the receipt, nature or value of any such benefits.

(f) It has received a copy of the Credit Agreement.

SECTION 9. Limitations on Obligations.

(a) The provisions of this Guaranty are severable, and in any action or proceeding involving any state corporate law, or any state, federal or foreign bankruptcy, insolvency, reorganization or other law affecting the rights of creditors generally, if the obligations of any Guarantor under this Guaranty would otherwise be held or determined to be avoidable, invalid or unenforceable on account of the amount of such Guarantor's liability under this Guaranty, then, notwithstanding any other provision of this Guaranty to the contrary, the amount of such liability shall, without any further action by such Guarantor, the Administrative Agent or the Lenders, be automatically limited and reduced to the highest amount that is valid and enforceable as determined in such action or proceeding (such highest amount determined hereunder being the relevant Guarantor's "Maximum Liability"). This Section 9(a) with respect to the Maximum Liability of any Guarantor is intended solely to preserve the rights of the Administrative Agent and the Lenders to the maximum extent not subject to avoidance under applicable law, and neither

any Guarantor nor any other Person or entity shall have any right or claim under this Section 9(a) with respect to the Maximum Liability, except to the extent necessary so that the obligations of any Guarantor hereunder shall not be rendered voidable under applicable law.

(b) The Guarantor agrees that the Guaranteed Obligations may at any time and from time to time exceed the Maximum Liability of Guarantor, and may exceed the aggregate Maximum Liability of any other guarantors, without impairing this Guaranty or affecting the rights and remedies of the Administrative Agent or the Lenders. Nothing in this Section 9(b) shall be construed to increase any Guarantor's obligations hereunder beyond its Maximum Liability.

(c) In the event any Guarantor (a "Paying Guarantor") shall make any payment or payments under this Guaranty or shall suffer any loss as a result of any realization upon any collateral granted by it to secure its obligations under this Guaranty, any other guarantor (each a "Non-Paying Guarantor") shall contribute to such Paying Guarantor an amount equal to such Non-Paying Guarantor's "Pro Rata Share" of such payment or payments made, or losses suffered, by such Paying Guarantor. For the purposes hereof, each Non-Paying Guarantor's "Pro Rata Share" with respect to any such payment or loss by a Paying Guarantor shall be determined as of the date on which such payment or loss was made by reference to the ratio of (i) such Non-Paying Guarantor's Maximum Liability as of such date (without giving effect to any right to receive, or obligation to make, any

contribution hereunder) or, if such Non-Paying Guarantor's Maximum Liability has not been determined, the aggregate amount of all monies received by such Non-Paying Guarantor from the Borrowers after the date hereof (whether by loan, capital infusion or by other means) to (ii) the aggregate Maximum Liability of all guarantors hereunder (including such Paying Guarantor) as of such date (without giving effect to any right to receive, or obligation to make, any contribution hereunder), or to the extent that a Maximum Liability has not been determined for any guarantors, the aggregate amount of all monies received by such guarantors from the Borrowers after the date hereof (whether by loan, capital infusion or by other means). Nothing in this Section 9(c) shall affect any Guarantor's or any other guarantor's several liability for the entire amount of the Guaranteed Obligations (up to such guarantor's Maximum Liability). Each Guarantor covenants and agrees that its right to receive any contribution under this Guaranty from a Non-Paying Guarantor shall be subordinate and junior in right of payment to all the Guaranteed Obligations. The provisions of this Section 9(c) are for the benefit of the Administrative Agent, the Lenders and the Guarantor and may be enforced by any one, or more, or all of them in accordance with the terms hereof.

SECTION 10. Notices. Any notice, demand, request or consent required or authorized hereunder shall be served in person or delivered by U.S. certified mail, return receipt requested, addressed as follows:

If to Guarantor:	c/o Unit Corporation 1000 Kensington Tower I, Tulsa, Oklahoma 74136 Fax: (918) 493-7711 Attention: General Counsel
If to the Lenders or the Administrative Agent:	BANK OF OKLAHOMA, N.A. Bank of Oklahoma Tower One Williams Center Tulsa, Oklahoma 74192 Attn: Energy Department - 8th Floor Fax: (918) 588-6880

or at such other address as the Guarantor or the Administrative Agent shall designate for such purpose in a written notice to the other parties. Notices served in person shall be effective and deemed given when delivered; and notices sent by certified mail shall be effective and deemed given three (3) Business Days after being deposited in the U.S. mail, postage prepaid.

SECTION 11. Survival. All warranties, representations and covenants made by the Guarantor herein or in any certificate or other instrument delivered by it or on its behalf hereunder shall be considered to have been relied upon by the Lenders and shall survive the execution and delivery of this Guaranty, regardless of any investigation made by the Administrative Agent or any of the Lenders. All statements in any such certificate or other instrument shall constitute warranties and representations by the Guarantors hereunder.

SECTION 12. Severability. Any remedy or right hereby granted which shall be found to be unenforceable as to any Person or under any circumstance, for any reason, shall in no way limit or prevent the enforcement of such remedy or right as to any other Person or circumstances, nor shall such unenforceability limit or prevent enforcement of any other remedy or right hereby granted.

SECTION 13. Collection Costs. The Guarantor agrees to reimburse the Administrative Agent upon demand for all reasonable out-of-pocket expenses (including reasonable attorneys' fees and legal expenses) incurred by the Administrative Agent or the Lenders arising out of or in connection with the enforcement of the Guaranteed Obligations or arising out of or in connection with any failure of the Guarantor to fully and timely perform their obligations hereunder.

SECTION 14. Governing Law. This Guaranty is made under and shall be governed by the laws of the State of Oklahoma, without giving effect to conflict of laws principles thereof.

SECTION 15. Jurisdiction and Venue. All actions or proceedings with respect to this Guaranty may be instituted in any state or federal court sitting in Tulsa County, Oklahoma, and by execution and delivery of this Guaranty, the Guarantor irrevocably and unconditionally (i) submits to the nonexclusive jurisdiction (both subject matter and Person) of each such court, and (ii)

waives (a) any objection that the Guarantors may now or hereafter have to the laying of

venue in any of such courts, and (b) any claim that any action or proceeding brought in any such court has been brought in an inconvenient forum.

SECTION 16. Waiver of Jury Trial. The Guarantor, the Administrative Agent and the Lenders (by their acceptance hereof) hereby voluntarily, knowingly, irrevocably and unconditionally waive any right to have a jury participate in resolving any dispute (whether based upon contract, tort or otherwise) betwe en or among the Borrowers or the Guarantor and the Administrative Agent or the Lenders arising out of or in any way related to this Guaranty. This Section 16 is a material inducement to the Lenders to provide the financing described herein or in the Credit Agreement.

ECTION 17. Additional Guarantors. Pursuant to Section 9.4 of the Credit Agreement, all future Material Subsidiaries of the Borrowers shall execute and deliver to the Administrative Agent a Guaranty Joinder Agreement, the form of which is attached hereto as Schedule I and made a part hereof. Upon the execution of a Guaranty Joinder Agreement, the Material Subsidiary shall be deemed to be a Guarantor for all purposes under this Guaranty and shall subscribe to and agree to be bound by all of the terms, conditions, agreements, covenants, and undertakings set forth in herein.

SECTION 18. Section Headings. The Section and subsection headings herein are for convenience only and shall not be deemed part of this Guaranty.

SECTION 19. Successors and Assigns. This Guaranty shall be binding upon the Guarantor and the Guarantor's successors and assigns and shall inure to the benefit of the Administrative Agent and the Lenders and their successors and assigns.

SECTION 20. Time of the Essence. The Guarantor acknowledges that time is of the essence with respect to the Guarantors' obligations under this Guaranty.

IN WITNESS WHEREOF, the Guarantor has caused this Guaranty to be duly executed as of the day and year first above written.

PETROCORP INCORPORATED,
a Texas corporation

By:_____
Name:_____
Title:_____

SCHEDULE I

GUARANTY JOINDER AGREEMENT

THIS GUARANTY JOINDER AGREEMENT (this "Joinder"), dated as of _____, 200_, is executed by _____, a _____ _____ (the "Additional Guarantor"), in favor of (i) the Lenders from time to time parties to the Credit Agreement described below and (ii) Bank of Oklahoma, National Association, as Administrative Agent under the Credit Agreement.

RECITALS

A. Unit Corporation, a Delaware corporation, Mountain Frond Pipeline Company, an Oklahoma corporation, Unit Drilling Company, an Oklahoma corporation, Unit Petroleum Company, Inc., an Oklahoma corporation, Petroleum Supply Company, an Oklahoma corporation, SerDrilco, Inc., an Oklahoma corporation, and Unit Energy Canada Inc., an Albert, Canada corporation (collectively, the "Borrowers"), the Lenders therein named, and Bank of Oklahoma, National Association, as Administrative Agent, are parties to that certain Credit Agreement dated effective as of January 30, 2004 (as amended, restated, supplemented or otherwise modified from time to time, the "Credit

Agreement"). Capitalized terms used herein and not otherwise defined herein have the respective meanings assigned to them in the Credit Agreement.

B. A Material Subsidiary has entered into that certain Guaranty Agreement dated effective as of January 30, 2004, in favor of the Lender and the Administrative Agent (as amended, restated, supplemented or otherwise modified from time to time, the "Guaranty"), pursuant to which such Material Subsidiary absolutely and unconditionally guaranteed, the full and punctual payment and performance of the Guaranteed Obligations, as more particularly set forth in the Guaranty.

C. The Additional Guarantor is a Material Subsidiary of the Borrowers, and pursuant to Section 9.4 of the Credit Agreement, the Borrowers are required to cause the Additional Guarantor to guarantee to the Administrative Agent the prompt payment and performance of the Guaranteed Obligations. The Additional Guarantor desires to execute and deliver this Joinder to satisfy such requirement.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Additional Guarantor agrees as follows:

SECTION 1. Guaranty. The Additional Guarantor hereby absolutely and unconditionally guarantees, jointly and severally, as a primary obligor and not as surety, the full and punctual payment (whether at stated maturity, upon acceleration or early termination or otherwise, and at all times thereafter) and performance of the Guaranteed Obligations (as such term is defined in the Guaranty), including, without limitation, any such Guaranteed Obligations incurred or accrued during the pendency of any bankruptcy, insolvency, receivership or other

similar proceeding, whether or not allowed or allowable in such proceeding. This Guaranty is a guaranty of payment and not just of collectibility and is in no way conditioned or contingent upon any attempt to collect from the Borrowers or upon any other event, contingency or circumstance whatsoever. If for any reason whatsoever the Borrowers shall fail or be unable duly, punctually and fully to pay such amounts as and when the same shall become due and payable, the Guarantors, without demand, presentment, protest or notice of any kind, will forthwith pay or cause to be paid such amounts to the Administrative Agent under the terms of the Credit Agreement, any Note or other relevant Loan Document, in lawful money of the United States, at the place specified in the Credit Agreement, or perform or comply with the same or cause the same to be performed or complied with, together with interest (to the extent provided for under the Credit Agreement) on any amount due and owing from the Borrowers.

SECTION 2. Binding Effect. This Joinder shall become effective when it shall have been executed by the Additional Guarantor and thereafter shall be binding upon the Additional Guarantor and shall inure to the benefit of the Lenders. Upon the effectiveness of this Joinder, the Additional Guarantor shall be deemed to be a Guarantor for all purposes under the Guaranty and shall subscribe to and agree to be bound by all of the terms, conditions, agreements, covenants, and undertakings set forth in the Guaranty, and this Joinder shall be deemed to be a part of and shall be subject to all the terms and conditions of the Guaranty. The Additional Guarantor shall not have the right to assign its rights hereunder or any interest herein without the prior written consent of the Administrative Agent.

SECTION 3. CHOICE OF LAW. THIS JOINDER SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE INTERNAL LAWS (AND NOT THE LAW OF CONFLICTS) OF THE STATE OF OKLAHOMA.

IN WITNESS WHEREOF, the Additional Guarantor has caused this Joinder to be duly executed and delivered by its duly authorized officer as of the date first above written.

_____,
a _____ _____

By:_____
Name:_____
Title: _____

SCHEDULE 1

PRICING SCHEDULE

Applicable Margin	Level I Status	Level II Status	Level III Status
Eurodollar Rate	1.00%	1.25%	1.50%
Floating Rate	0.00%	0.00%	0.00%

Applicable Margin	Level I Status	Level II Status	Level III Status
Commitment Fee Rate	0.375%	0.375%	0.375%

For the purposes of this Schedule, the following terms have the following meanings, subject to the final paragraph of this Schedule:

"Level I Status" exists at any date if the Borrowing Base Usage Percentage on such date is less than 50%.

"Level II Status" exists at any date if the Borrowing Base Usage Percentage on such date is greater than or equal to 50% and less than 75%.

"Level III Status" exists at any date if the Borrowing Base Usage Percentage on such date is greater than or equal to 75%.

"Status" means either Level I Status, Level II Status or Level III Status.

The Applicable Margin and Commitment Fee Rate will be determined on a daily basis in accordance with the foregoing table based on the Borrowing Base Usage Percentage on such day.

Letter of Credit Fees: Issuance Fees are payable quarterly in advance, determined as of the LC issue date based on the applicable Margin (Eurodollar Rate column) for Eurodollar Loans on the stated amount of the LC and an LC fronting fee of 0.125% per annum will be paid to the LC Issuer concurrent with execution.

SCHEDULE 2

LENDERS SCHEDULE

Lender	Maximum Credit Amount	% of Maximum Credit Amount
Bank of Oklahoma, N. A.	50,000,000	33.335%
Bank of America, N. A.	50,000,000	33.335%
BMO Nesbitt Burns Financing, Inc.	35,000,000	23.330%
Compass Bank	15,000,000	10.000%
TOTAL MAXIMUM CREDIT AMOUNT	150,000,000 (3)	100.00%

(3) Note: Borrowing Base, at Borrowers' designation, is initially reduced $120,000,000.00 although the Borrowing Base determined by the Lenders is $188,000,000.00.

SCHEDULE 3

DISCLOSURE SCHEDULE

1. Section 5.8 - Subsidiaries

Name	State/Country of Incorporation	Ownership Interest by Borrower
Unit Petroleum Company	Oklahoma	100% UC
Unit Drilling Company	Oklahoma	100% UC
Unit Texas Company	Oklahoma	100% UPC
Unit Drilling and Exploration Company	Delaware	100% UC
Petroleum Supply Company	Oklahoma	100% UC
Mountain Front Pipeline Company, Inc.	Oklahoma	100% UC
Unit Energy Canada Inc.	Alberta, Canada	100% UC
Superior Pipeline Company LLC	Oklahoma	40% UC
Unit Drilling Company International	Cayman Islands	100% UDC
Unit Acquisition Company	Texas	100% UC
Unit General LLC	Oklahoma	100% UPC
Unit Limited LLC	Oklahoma	100% UPC
UDC General LLC	Oklahoma	100% UDC
UDC Limited LLC	Oklahoma	100% UDC
SerDrilco, Inc.	Oklahoma	100% UC
Eagle Energy Partners I, L.P.	Texas	16.71% UC

2. Section 7.2 - Existing Indebtedness

King P. Kirchner Separation Agreement
Separation obligations under employee benefit plans
Customary gas balancing obligations
Prepayments for contract drilling services

3. Section 7.6(v) - Existing Liens

Existing liens in favor of Bank of Oklahoma on PetroCorp properties

4. Section 7.2 - Investments

Investment in Superior Pipeline Company, LLC
Investment in Eagle Energy Partners I, L.P.
Investment in public and private limited partnerships sponsored by Borrowers

SCHEDULE 4

SECURITY SCHEDULE

Second Amended And Restated Security Agreement, dated effective as of January 30, 2004, between and among Unit Drilling Company, an Oklahoma corporation, as debtor, and Bank Of Oklahoma, National Association, as collateral agent for Bank of America, N.A., BMO Nesbitt Burns Financing, Inc., Compass Bank, and Bank of Oklahoma, National Association.

SCHEDULE 5

ENVIRONMENTAL MATTERS

None. However, Borrowers are aware that the EPA takes the position that the building of oil and gas well sites is considered "construction" activity and not "oil and gas exploration and production operations" under the Clean Water Act and thus not exempt from the permitting requirements of the Clean Water Act. Borrowers believe that these activities are specifically exempted under Section 402(1)(2) of the Clean Water Act, despite the EPA's interpretation of that exemption. To date, the EPA has not taken any steps to enforce its position.

SCHEDULE 6

RATE MANAGEMENT TRANSACTIONS

Oil - Hedge transaction for 1,000 bbls/day dated January 9, 2004, effective February 1, 2004 and terminating December 31, 2004 with Bank of Oklahoma

Natural Gas - Hedge transaction for 10,000 mmBtus/day dated January 9, 2004, effective April 1, 2004 and terminating October 31, 2004 with Bank of America.

SCHEDULE 7

EXCLUDED ACCOUNTS

102657437	700148491
207923104	700147380
208331182	700170326
208335758	700171426
208341445	700173010
208346131	700175408
208351092	700176453
103840773	810039724
207928648	700149822
208332084	700106218
103570184	700149877

SCHEDULE 8

CONTINGENT OBLIGATIONS

- - Superior Pipeline Company LLC guarantee
- - Benefits payable under Health Plans
- - Benefits payable under Separation Benefit Plans
- - Earn Out Agreement in connection with SerDrilco acquisition
- - Benefits payable under Workers' Compensation plans
- - Benefits payable under Salary Deferral Plans

CONFIDENTIAL

For Private Placement Purposes Only

UNIT 2004 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP
7130 South Lewis, 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 January 8, 2004

600 Preformation
Units of Limited Partnership Interest
in the
UNIT 2004 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 600 (minimum of 50) units of limited partnership interest ("Units") in the UNIT 2004 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, 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; and
- 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.
- 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.
- 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.
- 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 UPON. 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 UPON 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, Esq.
7130 South Lewis, Suite 1000
Tulsa, Oklahoma 74136
(918) 493-7700

The following documents and instruments are available to qualified offerees upon 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 upon 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 Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, during calendar year 2003, the annual report to shareholders and all quarterly reports to shareholders submitted by UNIT to its shareholders during calendar year 2003.

8. The Registration Statement on Form S-3 (File No. 333-104165) and all supplemental prospectuses filed with the SEC pursuant to Rule 424.

9. The agreements of limited partnership for the prior oil and gas drilling programs and prior employee programs of Unit Petroleum Company, UNIT and Unit Drilling and Exploration Company ("UDEC").

10. All periodic reports filed with the Securities and Exchange Commission and all reports and information provided to limited partners in all limited partnerships of which Unit Petroleum Company, 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.

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EXHIBIT A - AGREEMENT OF LIMITED PARTNERSHIP
EXHIBIT B - LEGAL OPINION

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 2004 Employee Oil and Gas Limited Partnership, a proposed Oklahoma limited partnership (the "Partnership"), offers 600 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 hereto) must be executed 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 30, 2004 (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 upon delivery of the Subscription Agreement. Payment for the Units will be made either (i) in four equal Installments, the first of such Installments being due on March 15, 2004 and the remaining three of such Installments being due on June 15, September 15, and December 15, 2004, respectively, or (ii) through equal deductions from 2004 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 2004. Each member of the Board of Directors of UNIT may subscribe for up to 250 Units ($250,000). 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 upon 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, 2034, unless it is terminated earlier pursuant to 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."

Units will be offered only to those qualified employees of UNIT or any of its subsidiaries at the date of formation of the Partnership whose annual base salaries for 2004 have been set at $36,000 or more and directors of UNIT who meet certain financial requirements which will enable them to bear the economic risks of an investment in the Partnership and who can demonstrate that they have sufficient investment experience and expertise to evaluate the risks and merits of such an investment. 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 2004 have 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 2004. Directors' subscriptions may not be for more than 250 Units ($250,000). 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, 2005, 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. If oil and natural gas prices go down, the Partnership's distributions, if any, to the Limited Partners will be adversely affected.

- 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, 2005 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 upon 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 such 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 applicable retroactively.

- Certain allocations of income, gain, loss and deduction of the Partnership among 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.

- Investment as a Limited Partner may be less advisable for a person who does not have substantial current taxable income from trade or business activities in which the Limited Partner does not materially participate.

- 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 a 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 a well that may be dry or productive 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 may be encountered in drilling wells which could lead to substantial liabilities to third parties or governmental entities. In addition, 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 such laws and regulations.

Additional Financing

Additional Assessments. After the Aggregate Subscription received from the Limited Partners 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 from the Limited Partners 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. Additionally, the General Partner may, but is not required to, advance funds to the Partnership to pay such costs. See "ADDITIONAL FINANCING -- Partnership Borrowings."

Proposed Activities

General. The Partnership is being formed for the purposes of acquiring producing oil and gas properties and conducting oil and gas drilling and development operations. 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 commenced by UPC for its own account or by UNIT during the period from January 1, 2004, if the Partnership is formed prior to such date or from the date of the formation of the Partnership if subsequent to January 1, 2004, until December 31, 2004, and will, with certain limited exceptions, serve as a co-general partner with UNIT in any drilling or income programs which may be formed by the General Partner or UNIT in 2004. 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 UNIT during 2004. UNIT hopes that participation in the Partnership will provide the participants with greater proprietary interests in UNIT'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 UNIT realizes from the wells drilled or acquired during 2004.

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

pursuant to drilling activities in which the Partnership participates. The General Partner estimates (based on historical operating experience) that such costs may 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:

	$600,000 Program	$50,000 Program
Leasehold Acquisition Costs of Properties to Be Drilled.....	$30,000	$2,500
Drilling Costs of Exploratory Wells(1).....	30,000	2,500
Drilling Costs of Development Wells(1).....	420,000	35,000
Leasehold Acquisition Costs of Productive Properties.....	120,000	10,000
Reimbursement of General Partner's Overhead Costs(2).....	--	--
Total.....	$600,000	$50,000

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(1) See "GLOSSARY."

(2) The Agreement provides that the General Partner shall be reimbursed by the Partnership for that portion of its general and administrative overhead expense attributable to its conduct of Partnership business and affairs but such 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:

COSTS AND EXPENSES	General Partner	Limited Partners
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)

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(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, P.C. ("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 upon 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 and not as an association taxable as a corporation; (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 claim as deductions their pro rata shares of the Partnership's intangible drilling and development costs ("IDC") paid in 2004; (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 herein, 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.

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, or UNIT) and, in some 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 all such 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, may be fully liable for their proportionate share of all costs of such operations even if the actual costs significantly exceed the original cost estimates. Further, if any joint interest party defaults in its obligation to pay its share of the costs, the other joint interest parties may be required to fund 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 larger fractional interests in Partnership Properties than originally anticipated and, thus, be required to bear a greater share of the costs of operations. As a result of the foregoing, the Partnership could become liable for amounts significantly in excess of the amounts originally anticipated to be expended in connection with the operations and, in such event, would have only limited means for providing needed additional funds (see "ADDITIONAL FINANCING"). Also, if a well is operated by a company which does not or cannot pay the costs and expenses of drilling or operating a Partnership Well, the Partnership's interest in such 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 Upon General Partner

The Limited Partners will acquire interests in the Partnership, not in the General Partner or UNIT. They will not participate in either increases or decreases in the General Partner's or UNIT's net worth or the value of its 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 its operations, a significant financial reversal for the General Partner or UNIT could have an adverse effect on the Partnership and the Limited Partners' interests therein.

Under the Partnership 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, as the Limited Partners will have no role in the management of the business of the Partnership.

The Partnership's success will depend, in part, upon 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

UNIT and its 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 UNIT and its subsidiaries will continue to

engage in such 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 commenced by the General Partner or UNIT for its own account during the period from January 1, 2004, if the Partnership is formed prior to such date, or from the date of the formation of the Partnership, if subsequent to January 1, 2004, through December 31, 2004 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 2004. 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 UNIT or the General Partner prior to the formation of the Partnership. Further, certain of the Partnership Wells will be drilled on prospects on which the General Partner and possibly future employee programs may conduct additional drilling operations in years subsequent to 2004. 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 begun in 2004 and will have no rights in production from wells commenced in years other than 2004. Likewise, if additional interests are acquired in wells participated in by the Partnership after 2004, the Partnership will generally not be entitled to participate in the acquisition of such 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 of entering into each such contract, and the costs to be paid thereunder or the sale price to be received will be one which is competitive with the costs charged or the prices paid by unaffiliated parties in the same geographic region. The General Partner will make the determination of what are competitive rates or prices in the area. 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, however, that it will, if requested at any time after December 31, 2005, buy Units for prices determined either by an independent petroleum engineering firm or the General Partner pursuant to a formula described under "TERMS OF THE OFFERING -- Right of Presentment." This obligation of the General Partner to purchase Units when requested 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 have been made and may hereafter be made to investors in other oil and gas drilling, income and employee programs sponsored by the General Partner or UNIT. 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 2005. 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 upon 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 upon 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, upon 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 2004. 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 upon 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 upon exemptive provisions of said 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 exemptive provisions 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 upon 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

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 and 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 activities. For example, income from the Partnership's sale of 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 various of 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.

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 upon the opinion of Conner & Winters will not be challenged successfully by the Service.

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, 2004 or the time the Partnership is formed through December 31, 2004 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 2004.

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 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, 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 upon 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 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 (prior to the early 1980s), world oil prices were established and maintained largely as a result of the actions of members of OPEC to limit, and maintain a base price for, their oil production. Until recently, however, members of OPEC were unable to agree to and maintain price and production controls, which resulted in significant downward pressure on oil prices. Commencing in early 2001, OPEC members were able to reach agreement on oil production levels which has contributed to a rise in oil prices. Although future levels of production by the members of OPEC or the degree to which oil prices will be affected thereby 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

- 600 Maximum Units; 50 Minimum Units
- $1,000 Units; Minimum subscription: $2,000
- Minimum Partnership: $50,000 in subscriptions
- Maximum Partnership: $600,000 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 600 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 upon 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, Suite 1000, Tulsa, Oklahoma 74136, telephone (918) 493-7700.

The offering of Units will be closed on January 30, 2004 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 2004 (excluding bonuses) have 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 2004. Each director of UNIT may subscribe for a maximum of 250 Units (maximum investment of $250,000). At January 6, 2004 there were approximately 274 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, 2004 and the remaining three of such Installments being due on June 15, September 15, and December 15, 2004, respectively, or (ii) by employees so electing in the space provided on the Subscription Agreement, through equal deductions from 2004 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, 2005, 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 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 2003, Additional Assessments could be called for as provided herein. At September 30, 2003, 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 upon 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.

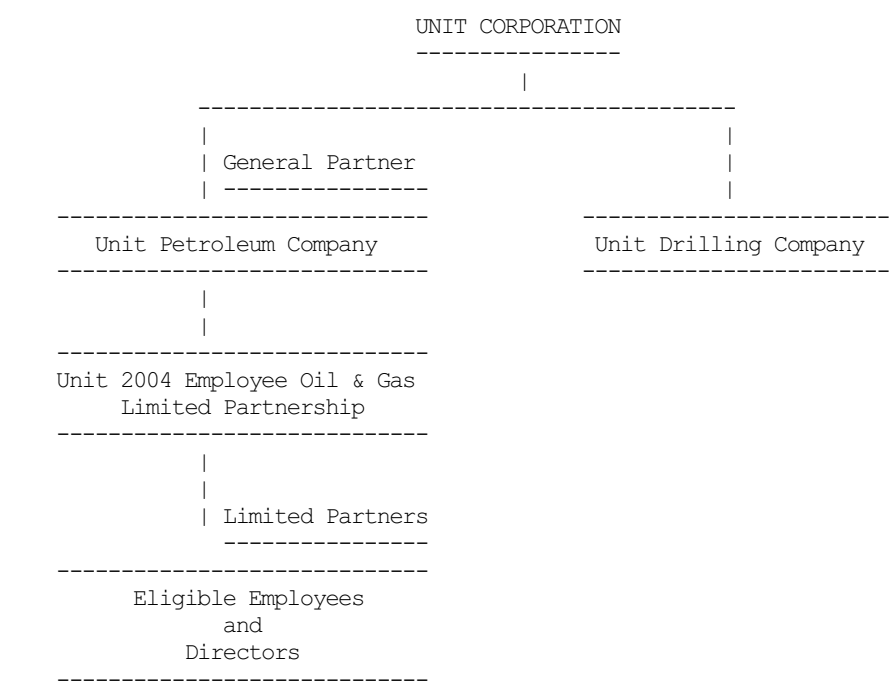
Suitability of Investors

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 2004. 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 2004 and (ii) serving as a co-general partner in any drilling or income programs, or both, formed by the General Partner or UNIT during 2004.

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, 2004, or the time of the formation of the Partnership if subsequent to January 1, 2004, until December 31, 2004, 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 (However, 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 2004. 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 2003. Although it does not currently contemplate doing so, UNIT may form such drilling or income programs during 2004. 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 2004 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 upon 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 2004 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 2004 nor can it predict what producing properties, if any, will be acquired by it during 2004. 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 150 - 200 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 2004. In either instance, the Partnership will have an interest only in those wells begun in 2004 and will have no rights in production from wells commenced in years other than 2004 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 2004, 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 2004. 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 2004.

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 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 upon 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 2004. If additional interests in Partnership Wells are

acquired in years subsequent to 2004 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 2004. 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 600 Units offered hereby are sold, the proceeds to the Partnership would be $600,000. 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:

	$600,000 Program	$50,000 Program

	Percent	Amount	Percent	Amount
Leasehold Acquisition Costs of Properties to Be Drilled.....	5%	$ 30,000	5%	$ 2,500
Drilling Costs of Exploratory Wells.....	5%	30,000	5%	2,500
Drilling Costs of Development Wells.....	70%	420,000	70%	35,000
Leasehold Acquisition Costs of Productive Properties.....	20%	120,000	20%	10,000
Total.....	100%	$ 600,000	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 2004 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, 2004 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, 2004 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		
o 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%
o All other Partnership Costs and Expenses:		
o Prior to time Limited Partner Capital Contributions are Entirely expended.....	1%	99%

o After expenditure of Limited Partner Capital Contributions and until expenditure of General Partner's Minimum Capital Contribution.....	100%	0%
o 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 most, if not all, Partnership Properties during the drilling of Partnership Wells and most, if not all, productive 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 a 40% interest in 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 as well as a 16.71% limited partnership interest in Eagle Energy Partners I, L.P., a Texas limited partnership, that buys and sells natural gas. It is possible that this limited partnership may buy some of the Partnerships natural gas production.

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, 2003, 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.....	-	300,505	964,738	829,503
1984 Employee(*).....	-	3,924	5,000	13,452
1985 Employee(*).....	-	10,316	-	54,892
1986 Energy Income Fund(**).....	-	343,912	1,224,907	64,945
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(*)(****).....	-	208,885	-	613
2000 Employee.....	-	60,314	-	600,771
2001 Employee.....	-	15,519	-	362,975
2002 Employee.....	-	7,229	-	274,089
2003 Employee.....	-	1,388	-	224,358

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(*) 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 - 2003 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 - 2003 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, 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 and in the exploration for and production of oil and 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	76	Director
John G. Nikkel	68	Chairman of the Board, Chief Executive Officer, Chief Operating Officer and Director
Larry D. Pinkston	49	President, Treasurer and Chief Financial Officer
Mark E. Schell	46	Senior Vice President, Secretary and General Counsel
O. Earle Lamborn	68	Senior Vice President, Drilling and Director
Philip M. Keeley	62	Senior Vice President, Exploration and Production
David T. Merrill	42	Vice President, Finance
William B. Morgan	59	Director
Don Cook	78	Director
John S. Zink	75	Director
John H. Williams	85	Director
J. Michael Adcock	54	Director
Mark E. Monroe	49	Director

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

Name	Age	Position
John G. Nikkel	68	Chairman of the Board and

		Director
Larry Pinkston	49	President and Treasurer
Philip M. Keeley	62	Executive Vice President and Director
Mark E. Schell	46	Secretary and General Counsel

Mr. Kirchner, a co-founder of UNIT, has been a director since 1963. He served as the Company'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 US Army during the Korean War and after that as vice-president engineering and operations for Woolaroc Oil Company.

Mr. Nikkel joined UNIT in 1983 as its President and a director. On July 1, 2001 Mr. Nikkel was elected to the additional office of Chief Executive Officer and served as President until July 31, 2003. 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. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Pinkston joined UNIT in December 1981. He had served as Corporate Budget Director and Assistant Controller prior to being appointed Controller in February 1985. He has been Treasurer since December 1986 and was elected to the position of Vice President and Chief Financial Officer in May 1989. In June 2003, he was elected to the additional position of President. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma and is a Certified Public Accountant.

Mr. Schell joined UNIT in January 1987, as its Secretary and General Counsel. In December 2002, he was elected to the additional position 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 and the American Society of Corporate Secretaries.

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

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

Mr. 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.

Mr. Morgan was elected a director of UNIT in February 1988. For over 5 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. Before that, he was a Partner in the law firm of Doerner, Saunders, Daniel & Anderson, Tulsa, Oklahoma, for over 20 years.

Mr. Cook has served as a director of UNIT since UNIT's inception. He is a Certified Public Accountant and was a partner in the accounting firm of Finley & Cook, Shawnee, Oklahoma, from 1950 until 1987, when he retired.

Mr. Zink was elected a director of UNIT in May 1982. For over 5 years, he has been a principal in several privately held companies engaged in the businesses of designing and manufacturing equipment used in the petroleum industry, construction, and heating and air conditioning services and installation. He holds a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University. He is also a director of Matrix Service Company, Tulsa, Oklahoma.

Mr. Williams was elected a director of UNIT in December 1988. Prior to retiring on December 31, 1978, he was Chairman of the Board and Chief Executive Officer of The Williams Companies, Inc. where he continues to serve as an honorary director. Mr. Williams also serves as a director of Apco Argentina, Inc., and Willbros Group, Inc. In addition, Mr. Williams also serves as a director of the Gilcrease Museum and 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 trust that deals in real estate, oil and gas properties and other equity investments. He is Chairman of the Board of Arvest Bank, Shawnee and a director of Community Health Partners, Inc., formerly Mid America Healthcare, 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. Monroe was the Chief Executive Officer and President of Louis Dreyfus Natural Gas Corp., a publicly-held natural gas exploration and production company, until the sale of the company in 2001. Prior to the formation of Louis Dreyfus Natural Gas in 1990, Mr. Monroe was the Chief Financial Officer of Bogert Oil Company, a publicly-held exploration and production company headquartered in Oklahoma City, Oklahoma. From 1976 to 1980, he was an Audit Manager for the public accounting firm of Deloitte & Touche in Dallas, Texas. Mr. Monroe currently serves as a member of the Board of Directors for Continental Resources, Inc., a privately-held exploration and production company headquartered in Enid, Oklahoma. He has served as President of the Oklahoma Independent Petroleum Association, on the Domestic Petroleum Council, on the National Petroleum Council and on the Boards of the Independent Petroleum Association of America and the Petroleum Club of Oklahoma City. Mr. Monroe graduated from the University of Texas at Austin with a BBA degree in 1975 and is a Certified Public Accountant.

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

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 2003 Employee Programs. The capital subscriptions of the following limited partners to the 2001, 2002 and 2003 Employee Programs were as shown below:

Subscriber	Position with UNIT	Amount of Capital Subscription		
		2001	2002	2003

King P. Kirchner	Director	$25,000 (1)	100,000 (1)	40,000
John G. Nikkel	Chairman, Chief Executive Officer, Chief Operating Officer and Director	$151,400 (2)	100,000 (2)	80,000
Earle Lamborn	Senior Vice President and Director	20,000 (3)	0	0
Philip M. Keeley	Senior Vice President, Exploration and Production	$43,600 (2)	40,000 (2)	20,000

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(1) Mr. Kirchner invested $25,000 indirectly in the 2001 Employee Program, $100,000 in the 2002 Employee Program and $40,000 in the 2003 Employee Program, through the King P. Kirchner Revocable Trust as permitted by the limited partnership agreement of those Employee Programs.

(2) Messrs. Nikkel and Keeley have invested in the 2001, 2002 and 2003 Employee Programs both directly and through Nike Exploration Company which until October of 2001 was owned 71.4% by Mr. Nikkel and members of his family and 28.6% by Mr. Keeley. Subsequent to October of 2001, Mr. Nikkel and members of his family were the sole owners of Nike Exploration Company. The amounts invested directly and indirectly through Nike Exploration Company in the 2001, 2002 and 2003 Employee Programs by Messrs. Nikkel and Keeley are set forth below:

Employee Program	Mr. Nikkel Directly	Mr. Keeley Directly	Nike Exploration Company
2001	$80,000	$15,000	$100,000
2002	$100,000	$40,000	$100,000
2003	$80,000	$20,000	$60,000

(3) Mr. Lamborn invested $20,000 indirectly in the 2001 Employee Program through the Earle Lamborn Revocable Trust as permitted by the limited partnership agreement.

Ownership of Common Stock

UNIT's Common Stock is listed on the New York Stock Exchange as reported on the Composite Tape. On January 5, 2004 there were 45,590,154 shares outstanding.

As of January 5, 2004, 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.....	446,920 (2)	*
John Williams.....	11,500 (3)	*
Don Cook.....	33,818 (3)	*
Philip M. Keeley.....	117,156 (2)(4)	*
Earle Lamborn.....	222,397 (2)(4)	*
John G. Nikkel.....	426,468 (2)(4)	*
Larry D. Pinkston.....	69,166 (2)(4)	*
Mark E. Schell.....	70,492 (2)(4)	*
John S. Zink.....	9,100 (3)	*
William B. Morgan.....	23,900 (3)	*
J. Michael Adcock.....	455,891 (3)(5)	*
Mark E. Monroe.....	1,000	*
All Officers and Directors as a Group.....	1,887,808 (2)(3)(4)(5)	

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*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 January 5, 2004, 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 January 5, 2004 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 January 5, 2004 for the account of: Earle Lamborn, 14,603; John G. Nikkel, 32,307; Philip M. Keeley, 12,616; Larry D. Pinkston, 3,491; and Mark E. Schell, 30,981.

(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, 26,500; William B. Morgan, 15,500; John H. Williams, 10,500; John S. Zink, 7,000; and King P. Kirchner 7,000 shares and all Non-Employee Directors as a group, 80,500.

(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 January 5, 2004 at the discretion of the holder: John G. Nikkel 47,500; Philip M. Keeley, 19,000; Larry D. Pinkston, 25,500; and Mark E. Schell, 25,500.

(5) Of the shares shown, Mr. J. Michael Adcock is deemed to be the beneficial owner of 440,891 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, 2004, or from the formation of the Partnership if subsequent to January 1, 2004, through

December 31, 2004 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 2004. 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, 2004, or from the formation of the Partnership if subsequent to January 1, 2004, through December 31, 2004. 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, 2004, or from the formation of the Partnership if subsequent to January 1, 2004, through December 31, 2004. Likewise the Partnership would have no interest in any increased density wells drilled on the original spacing unit unless such wells were drilled during 2004. In addition, if additional interests are acquired in wells participated in by the Partnership after 2004, 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 2004, 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 2004.

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 a 40% interest in Superior Pipeline Company, L.L.C. which is engaged in the business of buying and building gas gathering systems and a 16.71% limited partnership interest in Eagle Energy Partners I, L.P., a Texas partnership. Eagle is in the business of buying and selling natural gas. 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, P.C. 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 upon 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, 2003 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.

Year Ended	Gross Wells(2)				Net Wells(3)			
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	.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

Year Ended December 31(1)	Gross Wells (2) Total	Oil	Gas	Dry	Net Wells(3) Total	Oil	Gas	Dry
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
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

Year Ended December 31(1)	Gross Wells (2) Total	Oil	Gas	Dry	Net Wells(3) Total	Oil	Gas	Dry
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
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	21.80	.4	17.40	4.0
Total.....	51	1	42	8	21.80	.4	17.40	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

Year Ended	Gross Wells (2)				Net Wells(3)			
December 31(1)	Total	Oil	Gas	Dry	Total	Oil	Gas	Dry
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
Period of January 1, 2003 to September 30, 2003								
Exploratory.....	2	1	1	0	1.20	.20	1.00	0
Development.....	96	4	77	15	36.84	1.92	25.73	9.19
Total.....	98	5	78	15	38.04	2.12	26.73	9.19

(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 2003, 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%) 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 2 1/2% 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, 2003, and the economic results at September 30, 2003 of prior oil and gas programs and the 1984 - 2003 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, 2003

		Gross Wells				Net Wells			
Programs		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.....	8	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, 2003

Programs		Gross Wells				Net Wells			
		Total	Oil	Gas	Dry	Total	Oil	Gas	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.....	8	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

		Gross Wells				Net Wells			
Programs		Total	Oil	Gas	Dry	Total	Oil	Gas	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
Period of January 1, 2003 To September 30, 2003									
2003	Exploratory Wells.....	2	1	1	0	.03	.01	.02	0
Empl.	Development Wells.....	96	4	77	15	.92	.05	.64	.23
	Total.....	98	5	78	15	.95	.06	.66	.23

(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, 2003

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, 2003
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	2,545,708	2,271,101	31,366
1984 Employee(*)	1,542	1,745	-
1985 Employee(*)	2,820	1,808	-
1986 Energy Income Fund(**)	1,799,248	1,851,505	24,619
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	47,494
1992 Employee(****)	241,577	400,556	6,509
1993 Employee(****)	496,051	717,460	7,427
1994 Employee(****)	1,435,412	1,841,119	31,186
1995 Employee(****)	476,082	599,485	9,519
1996 Employee(****)	901,692	869,473	12,412
1997 Employee(****)	1,296,424	1,165,747	28,779
1998 Employee(****)	1,180,292	1,083,527	39,295
1999 Employee(****)	953,718	1,314,469	46,747
Consolidated Program	10,210	22,568	2,074
2000 Employee	1,941,548	2,062,871	78,569
2001 Employee	936,046	502,248	58,651
2002 Employee	948,069	449,315	92,208
2003 Employee	733,182	113,087	89,262

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(*) 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, 2003

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, 2003
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	3,179,316	2,365,703	31,366
1984 Employee(*)	120,942	171,540	-
1985 Employee(*)	277,901	178,984	-
1986 Energy Income Fund(**)	2,809,277	3,897,003	36,929
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.....	849,185	2,230,915	205,659
2000 Employee.....	271,226	281,428	10,713
2001 Employee.....	419,708	225,648	26,350
2002 Employee.....	489,134	231,466	47,501
2003 Employee.....	150,170	23,162	18,283

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(*) 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, 2003

Program	Total Expenditures Less Operating Costs(2)	Total Revenues Less Operating Costs	Total Revenues Less Operating Costs for 3 Months Ended Sept. 30, 2003	Total Revenues Distributed	Total Revenues Distributed for 3 Months Ended Sept. 30, 2003
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.....	934,572	659,965	8,981	984,834	27,550
1984 Employee(*)...	874	1,077	-	1,000	-
1985 Employee(*)...	2,300	1,288	-	1,035	-
1986 Energy Income Fund(**).....	177,078	229,335	5,455	472,865	-
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.	1,796	14,154	1,397	14,697	1,500
2000 Employee.....1,544,520		1,665,843	48,545	997,669	72,500
2001 Employee.....	857,480	423,682	49,713	223,000	56,000
2002 Employee.....	887,879	389,124	78,220	123,000	103,000
2003 Employee.....	720,838	100,743	78,752	-	-

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(*) 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, 2003

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, 2003	Total Revenues Distributed	Total Revenues Distributed for 3 Months Ended Sept. 30, 2003
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	2,036,778	1,223,164	18,312	952,286	27,720(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	988,116	2,075,841	8,184	1,952,500	10,400(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...	-	41,812	1,423,542	36,867	1,388,859	203,856 (7)
2000 Employee.....	199,000	210,969	221,171	6,626	202,781	12,537 (8)
2001 Employee.....	370,000	384,418	190,358	22,336	134,680	28,860 (9)
2002 Employee.....	457,000	457,392	199,723	40,292	133,444	60,781 (10)
2003						

Employee.....284,000 147,642 20,634 16,130 - - - ---------------

(*) 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 2003 the 1984 Program made a distribution of $22,680 to that program's limited partners.

(6) In November 2003 the 1986 Program made a distribution of $9,700 to that program's limited partners.

(7) In November 2003 the Consolidated Employee Program made a distribution of $142,432 to that program's limited partners.

(8) In November 2003 the 2000 Employee Program made a distribution of $8,756 to that program's limited partners.

(9) In November 2003 the 2001 Employee Program made a distribution of $21,460 to that program's limited partners.

(10) In November 2003 the 2002 Employee Program made a distribution of $31,990 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 upon 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 upon 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 upon the transactions described in this Memorandum (the "Transaction") and upon 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 2004. 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 herein, 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, due to the factual nature of the issue (See "Alternative Minimum Tax");

2. 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 and on the Partner's other oil and gas production; due to the inherently factual nature of such a determination, Conner & Winters is unable to render an opinion as to the availability of percentage depletion (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 upon 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 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, 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 properly elect 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 by not later than December 31, 2004. 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 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", 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 and believes that no person could reasonably infer from representations made, or to be made, in connection with the offering of Units that such sums as of such dates will exceed two times the Partners' cash investments as of such dates.

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.

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 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 should result in the treatment of the Nominee as the tax owner of the Partnership Properties. For the foregoing reasons, Conner & Winters have not expressed an opinion on this issue, but Conner & Winters 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 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 ("AMT") (see "Alternative Minimum Tax").

Although the General Partner will attempt to satisfy each requirement for deductibility of the Partnership's IDC in 2004, no assurance can be given that the Service will not successfully contend that the IDC of a Partnership well which is not completed until 2005 is not deductible in whole or in part until 2005. 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, 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 upon 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.

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.

Upon 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, upon 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 upon 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 upon 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.

Compliance Provisions. 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. 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 ($10,000 in the case of a corporation other than an S corporation or personal holding corporation).

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.

Individual Tax Advice Should Be Sought

The foregoing is only a summary of the material tax considerations that may affect an investor's decision regarding the purchase of Units. The tax considerations attendant to an investment in a Partnership are complex and vary with individual circumstances. Each prospective investor should review such tax consequences with his tax advisor.

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 upon 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 upon 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 depend largely upon 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"). Under the NGPA, natural gas is divided into numerous, complex categories based on, among other things, when, where and how deep the gas well was drilled and whether the gas was committed to interstate or intrastate commerce on the day before the date of enactment of the statute. These categories determine whether the natural gas remains subject to non-price regulation under the NGA and/or to maximum price restrictions under the NGPA. In addition to setting ceiling prices for natural gas, FERC approval is required for both the commencement and abandonment of sales of certain categories of gas in interstate commerce for resale and for the transportation of natural gas in interstate commerce. FERC has general investigatory and other

powers, including limited authority to set aside or modify terms of gas purchase contracts subject to its jurisdiction. Price and non-price regulation of natural gas produced from most wells drilled after 1978 has terminated. That gas may be sold without prior regulatory approval and at whatever price the market will bear.

On July 26, 1989, the Natural Gas Wellhead Decontrol Act of 1989 became effective. Consequently, due to this statutory deregulation and FERC's issuance of Order No. 547 discussed below, as of January 7, 1993 the price of virtually all gas produced by producers not affiliated with interstate pipelines has been deregulated by FERC.

Market determined prices for deregulated categories of natural gas fluctuate in response to market pressures which currently favor purchasers and disfavor producers. As a result of the deregulation of a greater proportion of the domestic United States gas market and an increased availability of natural gas transportation, a competitive trading market for gas has developed. For several reasons the supply of gas has exceeded demand. The General Partner cannot reliably predict at this time whether such supply/demand imbalance will improve or worsen from a producer's viewpoint.

During the past several years, FERC has adopted several regulations designed to create a more competitive, less regulated market for natural gas. These regulations have materially affected the market for natural gas.

FERC's initial major initiative was adoption of its "open-access transportation program," through Order No.s 436 and 500. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 Fed. Reg. 42,408 (October 18, 1985), vacated -------- and remanded, Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988), readopted on an ---------- ---------- interim basis, Order No. 500, 52 Fed. Reg. 30,344 (Aug. 14, 1987), remanded, American Gas Association v. FERC, 888 F.2d 136 (D.C. ---------- -------- ---------- Cir. 1989), readopted, Order No. 500-H, 54 Fed. Reg. 52,344 (Dec. 21, 1989), reh'g granted in part and denied in part, Order No. --------- ---------- 500-I, 55 Red. Reg. 6605 (Feb. 26, 1990), aff'd in part and remanded in part, American Gas Association v. FERC, 912 F.2d 1496 (D.C. ---------- ---------- Cir. 1990), cert. denied, 111 S. Ct. 957 (1991). Order 436 implemented three key requirements: (1) jurisdictional pipelines were ---------- required to permit their firm sales customers to convert their firm sales entitlements to a volumetrically equivalent amount of firm transportation service over a five-year period; (2) jurisdictional pipelines were required to offer their open-access transportation services without discrimination or preference; and (3) jurisdictional pipelines were required to design maximum rates to ration capacity during peak periods and to maximize throughput for firm service during off-peak periods and for interruptible service during all periods. The availability of transportation under Order 500 greatly expanded the free trading market for natural gas, including the establishment of an active and viable spot market.

Subsequently, in Order 636 the FERC focused on whether the resulting regulatory structure provided all gas sellers with the same regulatory opportunity to compete for gas purchasers. It decided that the form of bundled pipeline services (gas sales and transportation) was unduly discriminatory and anticompetitive. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Wellhead Decontrol, Order No. 636, 57 Fed. Reg. 13,267 (Apr. 16, 1992), III FERC Stats. & Regs. Preambles Paragraph 30,939, at 30,406; Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol, and Order Denying Rehearing in Part, Granting Rehearing in Part, and Clarifying Order No. 636, Order No. 636-A, 57 Fed. Reg. 36,128 (Aug. 12, 1992), III FERC Stats. & Regs. Preambles Paragraph 30,950; Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol; Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol; Order Denying Rehearing and Clarifying Order Nos. 636 and 636-A, Order No. 636-B, 57 Fed. Reg. 57,911 (Dec. 8, 1992).

Among other things, Order 636 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 (Straight Fixed Variable) to determine appropriate rates for those services. To the extent the pipeline company or its sales affiliate makes gas

sales as a merchant in the future, it will do so in direct competition with all other sellers pursuant to private contracts; however, pipeline companies have or will become "transporters only." Order 636 also allows pipeline companies to act as agents for their

customers in arranging the transportation of gas purchased from any supplier, including the pipeline itself, and to charge a negotiated fee for such agency services. The FERC required each pipeline company to develop the specific terms of service in individual proceedings and to submit for approval by FERC a compliance filing which set forth the pipeline company's new, detailed procedures.

In response to a Court remand, on February 27, 1997 FERC issued its final rule further revising Order 636. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 and Regulation of National Pipelines After Partial Wellhead Decontrol, 62 Fed. Reg. 10204 (Mar. 6, 1997). It modified its regulation by (i) changing the selection of a twenty-year matching term for the right of first refusal and instead adopting a five-year matching term and (ii) reversing the requirement that pipelines allocate 10% of GSR costs to interruptible customers and requiring that pipelines propose the percentage that interruptible customers will bear based on the individual circumstances present on each pipeline. Most of the individual pipeline restructurings arising from Order 636 have been completed.

In essence, the goal of Order 636 is to make a pipeline's position as gas merchant indistinguishable from that of a non-pipeline supplier. It, therefore, pushes the point of sale of gas by pipelines upstream, perhaps all the way to the wellhead. Order 636 also requires pipelines to give firm transportation customers flexibility with respect to receipt and delivery points (except that a firm shipper's choice of delivery point cannot be downstream of the existing primary delivery point) and to allow "no-notice" service (which means that gas is available not only simultaneously but also without prior nomination, with the only limitation being the customer's daily contract demand) if the pipeline offered no-notice city-gate sales service on May 18, 1992. Thus, this separation of pipelines' sales and transportation allows non-pipeline sellers to acquire firm downstream transportation rights and thus to offer buyers what is effectively a bundled city-gate sales service and it permits each customer to assemble a package of services that serves its individual requirements. But it also makes more difficult the coordination of gas supply and transportation.

The results of these changes could increase the marketability of natural gas and place the burden of obtaining supplies of natural gas for local distribution systems directly on distributors who would no longer be able to rely on the aggregation of supplies by the interstate pipelines. Such distributors may return to longer term contracts with suppliers who can assure a secure supply of natural gas. A return to longer term contracts and the attendant decrease in gas available for the spot market could improve gas prices. The primary beneficiaries of these changes should be gas marketers and the producers who are able to demonstrate the availability of an assured long-term supply of natural gas to local distribution purchasers and to large end users. However, due to the still evolutionary nature of Order 636 and its implementation, it is not possible at this time to project the impact Order 636 will have on the Partnership's ability to sell gas directly into gas markets previously served by the gas pipelines.

As a corollary to Order 636, FERC issued Order 547, which is a blanket certificate of public convenience and necessity pursuant to Section 7 of the NGA that authorizes any person who is not an interstate pipeline or an affiliate thereof to make sales for resale at negotiated rates in interstate commerce of any category of gas that is subject to the Commission's NGA jurisdiction. (There are certain requirements which must be met before an affiliated marketer of an interstate pipeline can avail itself of this certification.) Regulations Governing Blanket Marketer Sales Certificates, Order No. 547, 57 Fed. Reg. 57,952 (Dec. 8, 1992) (to be codified at 18 C.F.R. Sections 284.401 - .402). The blanket certificates were effective January 7, 1993, and do not require any further application by a person. The goal of Order 457, in conjunction with Orders 636, 636-A and 636-B, is to provide all merchants of natural gas a "level playing field" so that gas merchants who are not interstate pipelines are on an equal

footing with interstate pipeline merchants who are afforded blanket sales certificates pursuant to Order 636.

The FERC has also begun to allow individual companies to depart from cost-of-service regulation and set market-based rates if they can show they lack significant market power or have mitigated market power. See, e.g., Richmond Gas Storage Systems, 59 FERC Paragraph 61,316 (1992); El Paso Natural Gas Company, 54 FERC Paragraph 61,316, reh'g granted and denied in part, 56 FERC Paragraph 61,290 (1990); Transcontinental Gas Pipe Line Corp., 53 FERC Paragraph 61,446, reh'g granted and denied in part, 57 FERC Paragraph 61,345 (1991). Since the FERC has stated that "[w]here companies have market power, market-based rates are not appropriate," in order to "enhance productive efficiency in non-competitive markets," the FERC issued a rule allowing pipelines (and electric utilities) "to propose incentive rate mechanisms as alternatives to traditional cost-of-service regulations." Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities; Policy Statement on Incentive Regulation, 57 Fed. Reg. 55,231 (Nov. 24, 1992). The FERC has established five specific regulatory standards for implementing specific incentive mechanisms: they should (1) be prospective, (2) be voluntary, (3) be understandable, (4) result in quantifiable benefits to consumers including an upper limit on the risk to consumers that the incentive rates would be higher than rates they would have paid under traditional regulation, and (5) demonstrate how they maintain or enhance incentives to improve the quality of service.

Other regulatory actions have included elimination of minimum take and minimum bill provisions of pipeline sales tariffs (Order 380) and authorization of automatic abandonment authority upon expiration or termination of the underlying contracts (Order 490). FERC has also provided several forms of "blanket" certificates authorizing sales of gas with pregranted abandonment.

In addition, in Order 451, FERC established an alternative maximum lawful price for certain NGPA Section 104 and 106 gas produced from wells drilled prior to 1975 (so-called "old gas") which otherwise would be subject to lower ceiling prices. FERC provided, however, that the higher price could be collected only where the parties amended the contract or pursuant to complicated "good faith negotiation" rules which permit purchasers facing requests for increased prices to seek reduction of certain higher prices and authorize abandonment of both the higher cost and lower cost supplies if agreement cannot be reached. After the Fifth Circuit vacated Order 451 as an invalid exercise of FERC's authority, the United States Supreme Court reversed that decision and upheld the entirety of Order 451.

The issuance of Order 636 and its future interpretation, as well as the future interpretation and application by FERC of all of the above rules and its broad authority, or of the state and local regulations by the relevant agencies, could affect the terms and availability of transportation services for transportation of natural gas to customers and the prices at which gas can be sold on behalf of the Partnership. For instance, as a result of Order 636, many interstate pipeline companies have divested their gathering systems, either to unregulated affiliates or to third persons, a practice which could result in separate, and higher, rates for gathering a producer's natural gas. In proceedings during mid and late 1994 allowing various interstate natural gas companies' spindowns or spinoffs of gathering facilities, the FERC held that, except in limited circumstances of abuse, it generally lacks jurisdiction over a pipeline's gathering affiliates, which neither transport natural gas in interstate commerce nor sell gas in interstate commerce for resale. However, pipelines spinning down gathering systems have to include two Order No. 497 standards of conduct in their tariffs: nondiscriminatory access to transportation for all sources of supply and no tying of pipeline transportation service to any service by the pipeline's gathering affiliate. In addition, if unable to reach a mutually acceptable gathering contract with a present user of the gathering facilities, the FERC required that the pipeline must offer a two-year "default contract" to

existing users of the gathering facilities. However, on appeal, while the United States Court of Appeals for the District of Columbia upheld the FERC's allowing the spinning down of gathering facilities to a non-regulated affiliate, in Conoco Inc. v. FERC, 90 F.3d 536, 552-53 (D.C. Cir. 1996) the D.C. Circuit remanded the FERC's default contract mechanism. On February 18, 1997 the United States Supreme Court denied a petition to review the D. C. Circuit's decision. As a result of FERC's action, some states have enacted or are considering statutory and/or regulatory provisions to regulate gathering systems. Consequently, the General Partner cannot reliably predict at this time how regulation will ultimately impact 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 upon 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 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 2005. 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, 2034 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. Upon 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 Conner & Winters 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 upon 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 Conner & Winters, 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 2004 (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 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 Gifts 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 violative 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 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, upon 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 upon 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; o 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, 2034. In addition, upon 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.

Upon 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, P.C., 3700 First Place Tower, Tulsa, Oklahoma, 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 upon 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 upon 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. 1991, 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, 2004, 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, 2004, if any, minus (iii) the amount, if any, of the unexpended Aggregate Subscription at December 31, 2004.

(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, 2004 and December 15, 2004, respectively, or (ii) if an employee so elects, through equal deductions from 2004 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 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 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

On January 1, 1988 all of the oil and natural gas properties previously owned by Unit Drilling and Exploration Company ("UDEC") and UNIT were transferred into Sunshine Development Company through a contribution of capital. Included in the transfer were all interests previously owned by UDEC in numerous General and Limited Partnerships sponsored by UDEC. Effective February 1, 1988, Sunshine Development Company, a wholly owned subsidiary of UDEC, pursuant to an "Amended and Restated Certificate of Incorporation" was renamed Unit Petroleum Company and became a wholly owned subsidiary of UNIT.

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, 2003 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, 2003.

Unit Petroleum Company and Subsidiary
Consolidated Balance Sheet
(In Thousands)

October 31, 2003
(Unaudited)

Assets	
Current Assets:	
Cash and cash equivalents	$ 555
Trade accounts receivable	15,857
Materials and supplies, at lower of cost or market	4,014
Other	455
Total current assets	20,881
Property and Equipment:	
Oil and natural gas properties, on the full cost method	527,944
Other	424
	528,368
Less accumulated depreciation, depletion, amortization and impairment	235,621
Net property and equipment	292,747
Other Assets	43
Total Assets	$ 313,671
Liabilities and Shareholders' Equity	
Current Liabilities:	
Current portion of long-term liabilities	392
Accounts payable	7,431
Accounts payable to parent	16,268
Contract advances	858
Accrued liabilities	1,345
Total current liabilities	26,294
Other Long-Term Liabilities	12,308
Deferred Income Taxes	73,595
Shareholders' Equity:	
Common stock, $1.00 par value, 500 shares authorized and outstanding	1
Capital in excess of par value	31,543
Retained earnings	169,930
Total shareholders' Equity	201,474
Total Liabilities and Shareholders' Equity	$ 313,671

EXHIBIT A

UNIT 2004 EMPLOYEE OIL AND GAS LIMITED PARTNERSHIP

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UNIT 2004 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 2004 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, 2034, 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. 1991, 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, 2004, 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, 2004, minus (iii) the amount, if any, of the unexpended Aggregate Subscription at December 31, 2004.

(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, 2004, June 15, 2004, September 15, 2004, and December 15, 2004, respectively, or (ii) by employees so electing, through equal deductions from 2004 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 2004 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 2004 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, 2004 or the Effective Date through December 31, 2004 (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 2004 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 2004 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 2004 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 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 Gifts 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, 2005, 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 or would cause the Partnership to lose its status as a 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, 2034, 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, 2034, 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, 2004 but effective as of the Effective Date.

"General Partner"
UNIT PETROLEUM COMPANY

Attest:

By_____ By_____
Mark E. Schell, Secretary Larry D. Pinkston, President

(ALL INFORMATION WILL BE TREATED CONFIDENTIALLY)

Unit 2004 Employee Oil and Gas Limited Partnership
c/o Unit Petroleum Company
7130 South Lewis Avenue, Suite 1000
Tulsa, Oklahoma 74136

RE: Unit 2004 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 2004 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 January 8, 2004 of the Unit 2004 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 any of its subsidiaries at the date of formation of the Partnership whose annual base salary for 2004 has been set at $40,000 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 2004 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 2004 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, 2004, June 15, 2004, September 15, 2004 and December 15, 2004, respectively; or

_____ (b) through equal deductions from 2004 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		
_____	Mailing Address	
Please Print Name	if different:	

		TAX I.D. OR SOCIAL SECURITY NO.:
	_____	----------
Date: _____	_____	_____

ACCEPTED THIS _____ DAY OF _____, 2004.

UNIT 2004 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 should be returned to Unit 2004 Employee Oil and Gas Limited Partnership, Attention Mark E. Schell, 7130 South Lewis Avenue, Suite 1000, Tulsa, Oklahoma 74136. The General Partner, after acceptance, will return a copy of the accepted Subscription Agreement to the Limited Partner.

[CONNER & WINTERS LETTERHEAD]

January 8, 2004

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

Re: Unit 2004 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 2004 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 January 8, 2004 (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 November 30, 2003, 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.

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."ion, 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 2004.

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, due to the factual nature of the issue.

2. 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. Due to the inherently factual nature of such a determination, we are unable to render an opinion as to the availability of percentage depletion.

3. 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, 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, 2004. 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 and believes that no person could reasonably infer from representations made, or to be made, in connection with the offering of Units that such sums as of such dates will exceed two times the Partners' cash investments as of such dates.

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). Proposed Regulation 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. Rul73-211, 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. Treas. 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. Treas. 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, 2004. 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 2004; however, the General Partner has represented that any such well that is not completed in 2004 will be spudded by not later than December 31, 2004.

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 2004, will be allowable as a deduction in 2004, 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 2004, no assurance can be given that the Service will not successfully contend that the IDC of a well which is not completed until 2005 are not deductible in whole or in part until 2005.

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). Treas. 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. Treas. 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 Treas. 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. Treas. 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. Treas. 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. Treas. Reg. Section 1.465-22(a). "Personal funds" and "personal assets" are defined in Prop. Treas. 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. Treas. 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. Treas. 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 Treas. 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. Treas. 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. 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) $58,000 in the case of a joint return or a surviving spouse, (ii) $40,250 in the case of an individual who is not a married individual or a surviving spouse, and (iii) $29,000 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. For taxable years beginning after December 31, 1992, 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. For taxable years beginning after December 31, 1992, 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 eighteen months 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); Treas. 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.

Treas. 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 Treas. Reg. Section 1.714-1(b)(2)(ii)(d). Treas. 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. Treas. Reg. Section 1.704-1(b)(2)(iv).

Treas. 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.

Treas. 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 Regulation 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. Regulation 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.

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 Treasury Regulation 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. Treas. 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. Treas. Reg. Section 1.6662-3(b)(1)(iii). The term "disregard" includes any careless, reckless or intentional disregard of rules or regulations. Treas. 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. Treas. 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). Treas. 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. Treas. 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. Treas. 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. Treas. 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. Although definitive Treasury Regulations have not been promulgated 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.

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, P.C.

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT

Subsidiary	State or Province of Incorporation	Percentage Owned
Unit Drilling Company	Oklahoma	100%
Unit Petroleum Company	Oklahoma	100%
PetroCorp Incorporated	Texas	100%

Exhibit 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (File No.'s 333-83551, 333-99979 and 333-104165) and Form S-8 (File No.'s 33-19652, 33-44103, 33-49724, 33-53542, 33-64323, 333-38166 and 333-39584) of Unit Corporation, of our report dated February 18, 2004, relating to the financial statements and financial statement schedule, which appears in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 15, 2004

Exhibit 23.2

March 15, 2004

CONSENT OF RYDER SCOTT COMPANY, L.P.

We consent to incorporation by reference in the Registration Statements (File Nos. 333-683551, 333-99979, 333-104165) on Form S-3, and the Registration Statements (File Nos. 33-19652, 33-44103, 33-64323, 333-39584, 33-49724, 333-38166 and 33-53542) on Form S-8 of Unit Corporation of the reference to our reports for Unit Corporation, which appears in the December 31, 2003 annual report on Form 10-K of Unit Corporation.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.

Houston, Texas
March 15, 2004

Exhibit 31.1

CERTIFICATIONS UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John G. Nikkel, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 15, 2004

By: /s/ John G. Nikkel

JOHN G. NIKKEL
Chairman of the Board,
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

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

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

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

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

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

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

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

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

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

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

Date: March 15, 2004

By: /s/ David T. Merrill

DAVID T. MERRILL
Chief Financial Officer and
Treasurer (Principal Financial
Officer)

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, 2003 (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, 2003 and December 31, 2002 and for the years ended December 31, 2003, 2002 and 2001.

Dated: March 15, 2004

By: /s/ John G. Nikkel
- ----------------------
John G. Nikkel
Chief Executive Officer

Dated: March 15, 2004

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.