PROSPECTUS

PDC 2004-2006 DRILLING PROGRAM
$400 Million Offered ($7 Million Minimum Subscriptions)
Preformation General Partnership Units and Limited Partnership Units
$20,000 per Unit (Minimum Subscription - $5,000)

PDC 2004-2006 Drilling Program, which we refer to as the "program" in this prospectus, is a series of up to twelve limited partnerships which Petroleum Development Corporation, the managing general partner, will form to drill, own, and operate natural gas and oil wells in Colorado, Wyoming, Michigan, North Dakota, Alabama, West Virginia, New York, Pennsylvania, Utah, Texas and other states. The program intends to drill most or all of its wells in Colorado. We have completed the offering of our first six limited partnership, PDC 2004-A, -B, -C, and -D Limited Partnerships and PDC 2005-A and -B Limited Partnerships; these limited partnerships are currently conducting their respective businesses. This prospectus relates to the offering of securities of the program's four succeeding limited partnerships: PDC 2005-C, PDC 2005-D, and PDC 2006-A and PDC 2006-B Limited Partnerships.

These Securities Are Speculative and Involve a High Degree of Risk. See "Risk Factors" on page 5 for an explanation of the various risks involved in this offering. Investment risks and considerations include:

Drilling natural gas and oil wells is highly risky; you might lose your entire investment in the program.

No investor may participate in the management of any partnership.

The program has not yet selected any prospects for natural gas and oil drilling; thus, no investor can evaluate any prospect before investing.

Investors may be subject to unlimited liability.

No public market exists or will develop for the units; you may not be able to sell your units when or if you wish.

Significant tax considerations are involved in an investment.

We must sell a minimum of $7 million of units in a limited partnershipif we sell any units. We will sell units beyond the minimum amount on a best efforts basis. The offerings of limited partnerships designated PDC 2005- Limited Partnership will terminate on December 30, 2005; and of those designated PDC 2006- Limited Partnership will terminate on December 29, 2006. Branch Banking and Trust Company will hold subscription proceeds of each partnership in a separate escrow account and will not release funds to a partnership before the sale of the minimum number of that partnership's units. See "Plan of Distribution" on page __ for a discussion of the various terms and conditions involved in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Neither the attorney general of the State of New York nor the attorney general of the State of New Jersey nor the Bureau of Securities of the State of New Jersey has passed on or endorsed the merits of this offering. Any representation to the contrary is unlawful.

	Price to Public	Underwriting Discounts and Commissions	Proceeds to the Partnerships
Per Unit	$ 20,000	$ 2,100 (10.5%)	$ 17,900 (89.5%)
Total Minimum	$ 7,000,000	$ 735,000 (10.5%)	$ 6,265,000 (89.5%)
Total Maximum	$400,000,000	$42,000,000 (10.5%)	$358,000,000 (89.5%)

PDC Securities Incorporated, Dealer Manager
and an Affiliate of the Managing General Partner

The date of this prospectus is July 18, 2005.

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SUMMARY

This summary highlights material information from this prospectus. You should read the entire prospectus carefully and the attached appendices before you decide to invest. We direct prospective investors to the "Glossary of Terms" beginning on page __ for definitions of various technical terms appearing throughout the prospectus.

Business of the Partnerships

Each partnership will drill, own, and operate natural gas and oil wells which may be located in Colorado, Michigan, West Virginia, Pennsylvania, Utah, Wyoming, New York, North Dakota, Alabama, Texas and/or other states and will produce and sell natural gas and oil from these wells. The partnerships intend to drill most or all of their respective wells in Colorado; however, we may drill wells in other areas listed, if results of current and planned testing by the Managing General Partner are successful. Of the offering proceeds available for drilling operations, we plan to utilize most partnership proceeds in the drilling of development wells but may utilize up to 10% on one or more exploratory wells. A development well is a well which is drilled close to and to the same formation as wells which have already produced and sold oil or gas. An exploratory well is one which is drilled in an area where there has been no oil or gas production, or a well which is drilled to a previously untested or non-producing zone in an area where there are wells producing from other formations. See "Proposed Activities" (page __) for a discussion of the various business activities that we propose to undertake after the operations of a partnership commence.

The address and telephone number of the partnerships and Petroleum Development Corporation, the Managing General Partner, are 103 East Main Street, P.O. Box 26, Bridgeport, West Virginia 26330 and (304) 842-6256. See "Management" (page __) for information regarding the business and management of Petroleum Development Corporation.

Investment Objectives

This section discusses the investment objectives of the partnerships in PDC 2004-2006 Drilling Program. For reasons we discuss later in this summary and prospectus under "Risk Factors," you may not realize some or all of the benefits discussed below. You should only invest in this partnership if you can afford the loss of your entire investment.

The program provides you with an opportunity to invest in the drilling, completion, and production of natural gas and oil wells. The objective of the investment is to produce the following benefits for investors in the program:

Cash distributions from the sale of natural gas and oil. Investors will receive a portion of the cash profits from wells if we drill successful wells and if revenue from the wells exceeds expenses. We plan to drill partnership wells in areas where most successful wells continue to produce for 20 years or more. We expect to send the first partnership cash distribution to investors eight months after a partnership closes and drilling operations have commenced. Closing of a partnership occurs at the end of the last day that we accept subscriptions from investors.

A diversified investment in ten or more wells. We try to include at least ten wells in each partnership so that the impact of an unsuccessful well or wells is balanced by successful results of other wells. We also try to include wells from two or more geographic areas to offset poor results in one area by results in the other area.

Reduction of your taxes due in the year you make your investment. We have structured the partnership to allow you to deduct 88-89½% of your investment from your taxable income in the year you invest as intangible drilling costs, which we refer to as "IDC." Under federal tax law, your federal tax savings will be based upon the IDC deduction, your marginal income tax rate and the amount of your investment in the partnership. There are factors which may limit your ability to use the deductions to reduce taxes, and you may have to recapture some or all of the tax savings if you sell your partnership interest.

Accurate and timely reports, including Form K-1 tax information distribution in early February. We want you to know how and when your money is spent, what the operating results of the partnership are, and where the money you get in return comes from. We plan, prepare and distributeincome tax information on Form K-1 you need to prepare your income taxes in early February each year, even though the Internal Revenue Service deadline is April 15, so you can file your tax return when you are ready.

The production from natural gas and oil wells decreases as time passes, so your cash flow will also decrease over time. Natural gas and oil prices change constantly, so your cash flow can also increase or decrease from month to month. Your cash distributions will be partially sheltered from taxes by oil and gas percentage depletion.

You may not receive some or all of these investment benefits for a variety of reasons including those discussed under "Risk Factors" later in the prospectus.

<u>Terms of the Offering</u> (page __)

The Program. PDC 2004-2006 Drilling Program is a series of up to twelve limited partnerships to be formed under the West Virginia Uniform Limited Partnership Act, which we refer to in this prospectus as the West Virginia Act. In this prospectus, we refer to each as a "partnership" or in the plural as the "partnerships." We will offer and sell units of the various partnerships during 2004, 2005 and 2006. See "Terms of the Offering" (page __) for a discussion of the terms and conditions involved in making an investment in the program. **Each partnership when formed will constitute a separate business entity.** A limited partnership agreement will govern the rights and obligations of the partners of each partnership. We attach a form of the limited partnership agreement as Appendix A to the prospectus. See "Summary of Partnership Agreement" (page __) where we summarize the material features of the limited partnership agreement. The offering of the program's first six limited partnerships has been completed. We sold approximately $180 million of securities in these partnerships. All of these six partnerships have been funded and are currently conducting their respective businesses.

The Managing General Partner. The managing general partner of each partnership will be Petroleum Development Corporation, which we refer to in this prospectus as the "Managing General Partner" or sometimes as "PDC." See "Management" (page __) for a description of the business and management of PDC and the business experience of the senior officers and employees of PDC.

Units of Partnership Interest. You may choose to purchase units of general partnership interest or units of limited partnership interest in the particular partnership being offered. "Unit" means a partnership interest of a limited partner or of an additional general partner purchased by an investor partner. This interest is the right and obligation to share a proportional part of the investor partners' share of partnership income, expense, assets and liabilities. The fractional interest purchased by a one unit investment in the investor partners' interest in the partnership is the ratio of one unit to the total number of units sold. If you invest as an additional general partner, you will be able to apply tax deductions generated by the partnership to reduce your federal adjusted gross income regardless of the source of the income, but you will have unlimited liability for the drilling and completion activities of the partnership. If you are an individual investor and invest as a limited partner, you will be able to use your deductions only to reduce taxable income from passive sources. The Internal Revenue Service defines passive income as income from partnerships and rental activities. Your liability as a limited partner is restricted to your investment in the partnership. See "Terms of the Offering – Types of Units" (page __) for a discussion of the different aspects involved in an investment in limited partnership interests and general partnership interests.

Funding of a Partnership. In order to fund a partnership, we must sell a minimum of 350 units or $7,000,000 for each PDC limited partnership The maximum subscription for each limited partnership is 3,500 units or $70,000,000. We may choose to set a lower maximum subscription with respect to any of our remaining limited partnerships; we will revise our prospectus if we set a lower maximum subscription ceiling and that will occur before we commence the offering of a future partnership. If we set a lower maximum subscription ceiling, we will not change the minimum subscription amount of $7,000,000 with respect to that partnership. If you wish to see a table presenting the minimum and maximum subscriptions and the targeted offering termination and closing date for each partnership, see "Terms of the Offering – General" (page __).

Subscription and Escrow. All subscriptions are payable in cash upon subscription. We may not complete a sale of units to you until at least five business days after the date you have received a final prospectus. Once you submit your subscription and the five-day period has passed, your subscription is not revocable and you will not be able to get your subscription funds back, including the time your funds are in the escrow account, unless we do not complete the offering. We have selected Branch Banking and Trust Company, which we refer to in this prospectus as BB&T, as escrow agent to hold all subscription proceeds of each partnership in a separate interest-bearing escrow account. See "Terms of the Offering" (page __) for a discussion of how we will hold your subscriptions between our receipt of your funds and the time we close the offering or return your funds if we do not complete the offering.

Conversion of Units by the Managing General Partner and by Additional General Partners. We will convert all units of additional general partnership interest of a particular partnership into the same dollar amount of units of limited partnership interest of that partnership upon completion of drilling and completion operations of that partnership. Additional general partners may convert their units of additional general partnership interest into units of limited partnership interest if there is a material change in the amount of the partnership's insurance coverage. We must notify you if there is a material reduction of the insurance coverage, and you will be able to tell us to convert your interest any time during the 30 days preceding the change. You will not be able to convert your unit if the conversion would cause a termination of the partnership for federal tax purposes. See "Terms of the Offering – Conversion of Units by the Managing General Partner and by Additional General Partners" (page __), "Proposed Activities – Insurance" (page __), and "Tax Considerations – Conversion of Interests" (page __) for a discussion of the circumstances involved in converting units to limited partnership interests, the nature and extent of the insurance PDC carries, and the tax implications involved in a conversion of interests.

Unit Repurchase Program. Beginning with the third anniversary of the date of the first cash distribution of the particular partnership, investor partners of that partnership may request us to repurchase their units. Repurchase of units is subject to our financial ability to purchase the units. The purchase price will be not less than four times the most recent twelve months' cash distributions from production. See "Terms of the Offering – Unit Repurchase Program" (page __) and "Tax Considerations – Gain or Loss on Sale of Property or Units" (page __) for an explanation of how the repurchase program operates and for a discussion of the tax implications involved in a repurchase of units.

Suitability Standards – Long-Term Investment. We have instituted strict suitability standards for investment in the partnerships. You may not invest unless you satisfy the suitability requirements. Additionally, if you sell your units, the purchaser of your units must also meet the suitability requirements. See "Terms of the Offering – Investor Suitability" (page __) to see if you are eligible to purchase units in the program.

Risk Factors. This offering involves numerous risks, including the risks associated with natural gas and oil drilling and investments in natural gas and oil drilling programs, unlimited liability as an additional general partner, lack of a trading market in the units, and significant tax considerations. See "Risk Factors" (page __) and "Tax Considerations" (page __). You should carefully consider the significant risk factors inherent in and affecting the business of the partnerships and this offering before making an investment. You should also carefully read the "Tax Considerations" section of the prospectus and the tax opinion of our tax counsel in Appendix D to the prospectus for a discussion of the tax implications involved in an investment in units.

<u>Compensation of the Managing General Partner</u> (page __)

We and our affiliates will receive substantial compensation upon the formation and as a result of the operation of the partnership. We will receive fees for drilling and operating partnership wells, for marketing the natural gas produced by partnership wells, and for administering the partnerships, commissions and fees for selling the units of the partnerships, and a one-time management fee equal to 1½% of the aggregate subscriptions of the partnership upon closing of that partnership. The compensation payable to the Managing General Partner and its affiliates will reduce the amount of cash distributions to investors. See "Compensation to the Managing General Partner and Affiliates" (page __) where we discuss the Managing General Partner's equity interest in the partnership as well as the various fees, payments and reimbursements that the Managing General Partner and/or its affiliates will receive during the life of the partnership.

Participation in Costs and Revenues (page __)

Generally, investor partners will receive 75% and the Managing General Partner will receive 25% of partnership profits and losses throughout the term of each partnership. Amounts will be paid to partners only *after* payment of fees and expenses to the Managing General Partner and its affiliates and *only* if there is sufficient cash available. The investors' share of Partnership profits is increased to 85% and our share is decreased to 15% if the partnership does not average an annual return of 12.5% at any time during the first 10 years of the partnership. We calculate the average annual return as the sum of estimated initial tax savings of 25% of the investment plus investor cash distributions as a percentage of the investment, divided by the number of years since the closing of the partnership less eight months. You can see an example of this calculation on page __. The interests of the investor partners and us could also change if we invest additional funds for tangible drilling and lease costs. See "Participation in Costs and Revenues – Revenues – Revisions to Sharing Arrangements" (page __) and " – Costs – Lease Costs, Tangible Well Costs, and Gathering Line Costs" (page __). In these sections, we explain the revenues and costs allocations involved in operation of the partnership's business.

Application of Proceeds (page __)

We estimate that we will apply the proceeds from the subscriptions of the investor partners, prior to our cash contribution, which we must make as our capital investment upon closing of the partnership, as follows.

Activity	Percentage of Subscriptions
Drilling and Completion Costs	88.0%
Organization and Offering Costs	10.5%
Management Fee	1.5%
Total	100.0%

The organization and offering costs are comprised of soliciting dealer commissions, 7.0%; marketing support fee, 1.0%; due diligence reimbursement, .5%; and marketing and wholesaling fees and expenses, meeting costs and other expenses, 2.0%. Upon formation of the partnership, we will make our cash capital contribution equal to 24.4% of the investor partners' aggregate subscriptions. See "Source of Funds and Use of Proceeds" (page __), which presents the aggregate amount of capital a partnership will have upon formation, including our cash contribution, the organization and offering costs, the management fee, and the amount of funds that will be available to a partnership to drill its wells.

Tax Considerations; Opinion of Counsel (page __)

Duane Morris LLP has issued to us its opinion, concerning all material federal income tax issues applicable to an investment in the partnerships. See "Tax Considerations" (page __) for a discussion of the tax implications of an investment in the program. To fully understand these tax issues, you should read the tax opinion in Appendix D.

Rights of the Investor Partners (page __)

The limited partnership agreement, which we attach to this prospectus as Appendix A, sets forth your rights as an investor partner. For a summary of your rights, see "Summary of Limited Partnership Agreement."

RISK FACTORS

Investment in the partnerships involves a high degree of risk and is suitable only for investors of substantial financial means who have no need of liquidity in their investments. As a prospective investor, you should consider carefully the following factors, in addition to the other information in this prospectus, prior to making your investment decision.

Special Risks of the Partnerships

Drilling natural gas and oil wells is speculative, may be unprofitable, and may result in the total loss of your investment. The drilling and completion operations to be undertaken by each of the partnerships for the development of natural gas and oil reserves are speculative and involve the possibility of a total loss of your investment in a partnership. Drilling activities may be unprofitable, not only from non-productive wells, but also from wells which do not produce natural gas or oil in sufficient quantities or quality to return a profit on the amounts expended. Only one of the prior partnerships sponsored by us has, to date, generated cash distributions in excess of investor subscriptions without tax savings. See "Prior Activities – Participants' Net Cash Table" and " – Percentage of Gross Return on Subscriptions" which reflect, respectively, the cash distributed to the investor partners and the gross returns to investor partners considering the cash distributions and tax benefits attributable to an investment in prior partnerships. Investment is suitable only for individuals who are financially able to withstand a total loss of their investment. See "Terms of the Offering – Investor Suitability" (page __) to determine whether you qualify to invest in the program.

Spot market prices for natural gas typically have been lower in Colorado than spot market prices in the Eastern United States. Historically, prices for natural gas in Colorado have, on average, been lower than those nationally as reflected by the natural gas prices traded on the New York Mercantile Exchange ("NYMEX"). For the years 1999 through 2004, Colorado natural gas prices as indicated by the Colorado Interstate Gas ("CIG") monthly index ranged from $1.20 per MMBtu to $8.63 per MMBtu, while during the same timeframe, the last day's settled price for Natural Gas NYMEX contracts ranged from $1.67 per MMBtu to $9.98 per MMBtu. For that period of 1999 through 2004, the average percentage relationship of the CIG monthly index was 79.7% of the NYMEX settled price. For the period from June 2003 through May 2005, the average percentage relationship of the CIG monthly index was 85.8% of the NYMEX settled price.

Investors can anticipate an extended period before they achieve payout on their investment in the partnership. Estimated payout periods of the various partnerships, which have conducted their drilling operations in Colorado, sponsored by the Managing General Partner from 1999 through 2004 range from 6 to 14 years based on estimated future net revenues of these various partnerships. See "Participants' Estimated Future and Total Payout and Payout Period" table below under "Prior Activities."

There will be no public market for the units, and as a result an investor partner may not be able to sell his or her units. There will be no public market for the units nor will a public market develop for the units. You may not be able to sell your partnership interests or may be able to sell them only for less than fair market value. A sale or transfer of units by you requires our prior written consent. For these and other reasons, an investor must anticipate that he or she will have to hold his or her partnership interests indefinitely and will not be able to liquidate his or her investment in the partnership. Consequently, an investor must be able to bear the economic risk of investing in the partnership for an indefinite period of time. See "Transferability of Units" (page __) for a discussion of the limited liquidity of a purchase of units and how you might sell your units.

The Managing General Partner has not selected any prospects for acquisition, and as a result the investor partners will be unable to evaluate any prospect before they invest in the program. We have not selected any prospect for acquisition by any partnership and will not select prospects for a particular partnership until after the activation of that partnership. You will not have an opportunity before purchasing units to evaluate for yourself the relevant geophysical, geological, economic or other information regarding the prospects to be selected. See "Proposed Activities – Acquisition of Undeveloped Prospects" (page __) for a description of how we will select prospects for the partnership.

Because of a lengthy offering period, delays in the investment of an investor's subscription are likely; because of the delay, you can expect a delay in any cash distributions from the partnership to you. Upon execution and delivery by you, your subscription will be irrevocable and cannot be withdrawn. Because the offering period for a particular partnership can extend for up to five months, delays in the investment of proceeds from your initial subscription date are likely. As a result, you will be unable to invest funds in other investments. Also, because of the delay in the investment, there will be a delay in cash distributions to you by the partnership. Cash distributions will be paid only after payment of fees and expenses to the Managing General Partner and its affiliates and only if there is sufficient cash available.

See "Terms of the Offering – General" (page __) for a discussion of the procedures involved in the offering and in the formation of a partnership.

If the partnership's securities offering closes earlier than expected, drilling rigs may not be available to begin drilling operations; consequently, drilling of partnership wells could be delayed, which would also delay the payment of initial cash distributions from drilling operations to the partnership's investors. Recently, sales of partnerships' securities have concluded in a matter of days or weeks following commencement of the particular partnership's securities offering. In a number of instances, no drilling rigs were available to begin drilling those partnerships' wells until close to the respective partnership's scheduled offering closing date. Therefore, drilling operations in those instances did not commence for 30 to 90 days following completion of the offering. The delay in drilling and completing those partnerships' wells resulted in a delay in the payment of the initial cash distribution for 30 to 90 days beyond the Managing General Partner's historical experience. The Managing General Partner's historical experience has been to make initial cash distributions to the partnership's investors approximately six months following funding of the partnership. We cannot predict how long the securities offering of the partnership will remain open. Therefore, it is possible that we could experience similar delays in the commencement of the partnership's drilling operations and in the payment of initial cash distributions to the investors of the partnership.

Additional general partners will be individually liable for partnership obligations and liabilities beyond the amount of their subscriptions, partnership assets, and the assets of the Managing General Partner. Under West Virginia law, the state in which each partnership will organize, general partners of a partnership have unlimited liability with respect to that partnership. Therefore, the additional general partners will be liable individually and as a group for all obligations and liabilities of creditors and claimants, whether arising out of contract or tort, in the conduct of partnership operations. If you invest as an additional general partner, you may be liable for amounts in excess of your subscriptions, the assets of the partnership, including insurance coverage, and the assets of the Managing General Partner.

The Managing General Partner and its affiliates will receive compensation from the partnership upon funding of the partnership and throughout the life of the partnership; these compensation payments could result in conflicts of interest by the Managing General Partner and its affiliates; compensation payments made to the Managing General Partner and its affiliates will reduce the amount of cash distributions that investors may receive. We will receive compensation throughout the life of the partnership. These compensation payments may result in conflicts of interest between the Managing General Partner and its affiliates and the investor partners and might lead us to take actions not most advantageous to the partnership. See "Conflicts of Interest" for a discussion of the conflicts of interest that may be present in connection with the operation of the partnership. In addition, the payment of compensation to the Managing General Partner and its affiliates will reduce the amount of cash distributions that investor partners may receive from the partnership. See "Compensation to the Managing General Partner and Affiliates" (page __) for a discussion of fees, payments and reimbursements that the Managing General Partner and its affiliates will receive upon organization of the partnership and during its operating life.

The partnership's wells might not produce commercial quantities of natural gas or oil; as a result, your investment in the partnership might not be profitable. The selection of prospects for natural gas and oil drilling is inherently speculative and is subject to a high degree of risk. We cannot predict whether any prospect will produce natural gas or oil or commercial quantities of natural gas or oil. We cannot predict the life and production of any well. The actual lives could differ from those anticipated. Partnership wells may not produce sufficient gas and oil for investors to receive a profit or even to recover their initial investment. See "Proposed Activities – Acquisition of Undeveloped Prospects" (page __) for a discussion of how we will select prospects for the partnership.

Our retention of partnership revenues to pay for additional development work would result in a reduction of cash distributions to investors in the short term and may not increase cash distributions in the long term. If development work is unsuccessful, no additional oil and gas may be produced, so there will not be an increase in cash distributions to offset those amounts withheld to pay the costs of the work. We intend initially to develop partnership properties only with the proceeds of the subscriptions and our capital contribution. However, these funds may not be sufficient to fund all of the partnership's development costs. In the future we may wish to rework or recomplete partnership wells and we will not hold money from the initial investment for that future work. As a result, the partnership may choose to borrow funds or retain revenues from its operations to pay for these development costs. The partnership's borrowing or retaining funds for further development could reduce the amount of cash distributions to the investors. See "Source of Funds and Use of Proceeds" for a discussion of the sources of partnership capital and our intended uses of that capital.

<u>Withholding funds for development work will decrease your cash distributions but may not decrease the taxes you must pay</u>. Even though you do not receive the cash withheld to pay development costs, the Internal Revenue Service may consider some or all of the funds withheld as taxable income to you. So you could owe taxes on the income without cash from the partnership to pay the tax. If we retain funds for development work, it will reduce the amount of your cash distributions when the funds are being deducted, may not increase future cash flow, and may result in "phantom income" to you. Phantom income is income you must report as taxable income on your tax return even though you have not received the cash because it was used to fund the additional development work. See "Tax Considerations" for a discussion of the tax implications of an investment in the program.

<u>Sufficient insurance coverage may not be available for the partnership, thereby increasing the risk of loss for the investor partners</u>. It is possible that some or all of the insurance coverage which the partnership has available may become unavailable or prohibitively expensive. In that case, we may elect to change the insurance coverage. See "Proposed Activities – Insurance" (page __) for a discussion of the extent of our insurance coverage. Additional general partners could be exposed to additional financial risk due to the reduced insurance coverage and due to the fact that additional general partners would continue to be individually liable for obligations and liabilities of the partnership. As an investor partner, you could be subject to greater risk of loss of your investment since less insurance would be available to protect your partnership from casualty losses. Moreover, the partnership's carrying of more expensive insurance will reduce the amount of cash distributions to the investors.

<u>A partnership which drills fewer wells will be less diversified, thereby increasing the risk of financial loss for the investors</u>. We intend to spread the risk of natural gas and oil drilling by participating in wells on a number of different prospects. However, the cost of drilling wells in different geographic locations varies greatly. A partnership subscribed at the minimum level or which drills more expensive wells would be able to participate in fewer prospects, resulting in a decrease of the diversification of the partnership's investment in prospects and an increase of your risk of financial loss of that partnership. See "Proposed Activities – Drilling and Completion Phase – Drilling and Operating Agreement" (page __) for a discussion of the drilling and operating agreement that will govern the partnership's activities and of the costs involved in drilling and operating the partnership's wells.

<u>Through their involvement in partnership and other non-partnership activities, the Managing General Partner and its affiliates have interests which conflict with those of the investor partners; actions taken by the Managing General Partner in furtherance of its own interests could result in the partnership's being less profitable and a reduction in cash distributions to the investors</u>. Our continued active participation in oil and gas activities for our own account and on behalf of other partnerships organized or to be organized by us, our sale of leases to and other transactions with the partnerships, and the manner in which partnership revenues are allocated create conflicts of interest with the partnerships. We have interests which inherently conflict with your interests. In operating the partnership, the Managing General Partner and its affiliates could take actions which benefit themselves and which do not benefit the partnership. These actions could result in the partnership's being less profitable. In that event, an investor partner could anticipate a reduction of cash distributions. See "Conflicts of Interest" (page __) for a discussion of the various conflicts involved as a result of the Managing General Partner's activities.

<u>Unaffiliated persons might manage jointly-owned partnership prospects; a partnership could be financially liable for obligations of jointly-owned prospects; as a result, the expenses of the partnership might increase and the cash distributions to investors might decrease</u>. The partnerships will usually acquire less than the full working interest in prospects and, as a result, will engage in joint activities with other working interest owners. Additionally, the partnership might purchase less than a 50% working interest in one or more prospects. As a result, someone other than the partnership or us may control and manage the partnership's prospects. A partnership could be held liable for the joint activity obligations of the other

working interest owners, including nonpayment of costs and liabilities arising from the actions of the working interest owners. Full development of the prospects could be jeopardized in the event of the inability of other working interest owners to pay their respective shares of drilling and completion costs. As a result, the expenses of that partnership would increase, and cash distributions to you by that partnership would be less than what you had anticipated. See "Proposed Activities – Drilling and Completion Phase – Drilling and Operating Agreement" (page __) for a discussion of the drilling and operating agreement that will govern the partnership's activities.

The partnership may borrow funds if needed for partnership operations to fully develop the partnership's wells; if full development of the partnership's wells proves commercially unsuccessful, an investor might anticipate a reduction in cash distributions. The partnership intends to utilize substantially all available capital from this offering for the drilling and completion of wells and will have only nominal funds available for partnership purposes prior to the time as there is production from partnership well operations. The limited partnership agreement permits the partnership to borrow money as may be required for further development of the partnership's wells. All borrowing will be non-recourse to the investor partners; this means that the partnership, not the investor partners, will be responsible for repaying the loan. There is no assurance that future development of the partnership's wells will prove commercially successful and that the further-developed partnership wells will generate funds from production greater than the financial obligation of the partnership to repay the borrowed funds plus interest. If future development of the partnership's wells is not commercially successful, an investor might anticipate a reduction in cash distributions from the partnership. If the partnership conducts further development operations, whether using borrowed funds or funds from production, these operations could result in a reduction of cash distributions to the partners of that partnership. See "Source of Funds and Use of Proceeds – Subsequent Source of Funds" (page __) and "Proposed Activities – Production Phase of Operations – Expenditure of Production Revenues" (page __) for a discussion of the funds available to the partnership for its drilling and operating activities.

The partnership and other partnerships sponsored by the Managing General Partner may compete with each other for prospects, equipment, contractors, and personnel; as a result, the partnership may find it more difficult to operate effectively and profitably. During and after 2005, we plan to offer interests in other partnerships to be formed for substantially the same purposes as those of the partnerships. Therefore, a number of partnerships with unexpended capital funds, including those partnerships formed before and after the partnerships, may exist at the same time. Due to competition among partnerships for suitable prospects and availability of equipment, contractors, and our personnel, the fact that partnerships previously organized by us may still be purchasing prospects and requiring equipment, contractors and our personnel (when the partnership is attempting to purchase prospects and is also needful of equipment, contractors and our personnel) may make more difficult and more costly prospect acquisition and completion activities by a partnership. In that event, it is possible that the partnership would be less profitable. Additionally, because we must divide our attention in the management of our own affairs as well as the affairs of the 74 limited partnerships we have organized in the current program and previous programs, the partnership in which you invest will not receive our full attention and efforts at all times.

The partnership may drill exploratory wells, which involves a greater risk of financial loss than drilling development wells. Each partnership may drill one or more exploratory wells. Drilling exploratory wells involves greater risks of dry holes and loss of your investment. A dry hole is a well which does not find enough oil or gas to justify the cost of completing the well. Dry holes must be plugged with cement and have the surface restored to near its original condition. Drilling development wells generally involves less risk of dry holes but developmental acreage is more expensive and subject to greater royalties and other burdens on production. If we drill unsuccessful wells, whether exploratory or developmental wells, your investment in the partnership might not be profitable. See "Proposed Activities" (page __) for a discussion of our proposed drilling program and how we intend to use the funds of the partnership.

The results of drilling previous partnerships sponsored by the Managing General Partner are not indicative of the results to be experienced by the partnerships; your investment in the partnership might not be profitable. The partnership in which you invest may not be as successful as partnerships of previous programs sponsored by us. As a result, you should not consider information concerning the prior drilling experience of previous partnerships sponsored by us, presented under the caption "Prior Activities" (page __), as being indicative of the results you might expect from your investment in these partnerships. Your investment in the partnership might not be profitable.

In view of the cost sharing arrangements, the investor partners will bear the substantial amount of costs and risks of non-commercial wells. Under the cost and revenue sharing provisions of the limited partnership agreement, we and the investor partners may share in costs disproportionate to our respective sharing of revenues. Because the investor partners will bear the substantial amount of costs of acquiring, drilling and developing the prospects, the investor partners will bear the substantial amount of costs and risks of drilling dry holes and marginally productive wells. See "Participation in Costs and Revenues" (page __) for a description of the costs and revenues sharing arrangements between the Managing General Partner and the investors.

Investor partners may be personally liable if they violate the limited partnership agreement. As an investor partner, you may not participate in the management of partnership business. The limited partnership agreement forbids you as an investor partner from acting in a manner harmful to the business of the partnership. If you violate the terms of the limited partnership agreement, you may have to pay for those losses and may also have to pay other partners for all damages resulting from your breach of the limited partnership agreement. See "Summary of Limited Partnership Agreement" (page __) for a description of your rights as a partner of the partnership.

Indemnification of additional general partners by the Managing General Partner could reduce the value of the partnership and the investment interests of the investor partners. We have agreed to indemnify each of the additional general partners for obligations related to casualty and business losses which exceed available insurance coverage and partnership assets. Any successful claim of indemnification might reduce the value of the partnership. As a result, the value of your investment interest in the partnership would be reduced. In the event of a successful claim, you could lose your entire investment in the partnership. See "Summary of Partnership Agreement – Indemnification" (page __) for a discussion of the indemnification provisions of the limited partnership agreement.

Receipt by investor partners of partnership distributions could result in liability of the investor partners to the partnership If investor partners receive a return of any part of their capital contributions to a partnership, without violation of the limited partnership agreement or the West Virginia Act, those partners will be liable to the partnership for a period of one year after the return for the amount of the returned contributions. If the return is in violation of the limited partnership agreement or the West Virginia Act, those partners will be liable to the partnership for a period of six years after the return for the amount of the contribution wrongfully returned.

A significant financial loss by the Managing General Partner could result in our inability to indemnify additional general partners for personal losses suffered because of partnership liabilities. As a result of our commitments as general partner of several partnerships and because of the unlimited liability of a general partner to third parties, our net worth is at risk of reduction if we suffer a significant financial loss. Because we are primarily responsible for the conduct of the partnership's affairs, as well as the affairs of other partnerships for which we serve as managing general partner, a significant adverse financial reversal for us could result in our inability to pay for partnership liabilities and obligations. Additional general partners might be personally liable for payments of the partnership's liabilities and obligations. Therefore, the Managing General Partner's financial incapacity could increase your risk of personal liability as an additional general partner because PDC would be unable to indemnify you for any personal losses you suffered. See "Prior Activities – Prior Partnerships" (page __) for a description of the extent of our financial obligations as managing general partner of other limited partnerships.

An investor partner may not receive a cash distribution if the distribution would cause a capital account deficit. The limited partnership agreement prohibits you from receiving allocations or cash distributions to the extent the allocation or distribution would create deficits in your capital account. A deficit would occur, for example, if the sum of the expenses and losses allocated to a partner plus the distributions made to you exceed the sum of the income and gains allocated to you plus the amount you paid for your partnership interest. See "Tax Considerations" for a discussion of allocations and distributions.

The dealer manager is not independent and has not conducted an independent due diligence evaluation of the offering. PDC Securities Incorporated, the dealer manager of this offering, is our affiliate and is not independent which creates a conflict of interest in its due diligence examination and evaluation of this offering.

Risks Pertaining to Natural Gas and Oil Investment

The drilling of natural gas and oil wells is highly speculative and risky and may result in unprofitable wells. Natural gas and oil drilling is a highly speculative activity marked by many unsuccessful efforts. You must recognize the possibility that the wells drilled may not be productive. Even completed wells may not produce enough natural gas or oil to show a profit. Delays and added expenses may also be caused by poor weather conditions affecting, among other things, the ability to lay pipelines. In addition, ground water, various clays, lack of porosity, and permeability may hinder or restrict production or even make production impractical or impossible. Any of these events could cause the partnership not to be profitable. See "Proposed Activities" (page __) for a discussion of our drilling program.

The prices for natural gas and oil have been quite unstable; a decline in the price could cause the partnership to be unprofitable. Global economic conditions, political conditions, and energy conservation have created unstable prices. Revenues of each partnership are directly related to natural gas and oil prices which we cannot predict. The prices for domestic natural gas and oil production have varied substantially over time and by location and may in the future. A decline in gas and/or oil prices would result in lower revenues for the partnership and a reduction of cash distributions to the partners of that partnership. Prices for natural gas and oil have been and are likely to remain extremely unstable. See "Competition, Markets and Regulation" (page __) for a discussion of the marketing and pricing of natural gas and oil.

Fluctuating market conditions and government regulations may cause a decline in the profitability of the partnership. The sale of any natural gas and oil produced by the partnerships will be affected by fluctuating market conditions and regulations, including environmental standards, set by state and federal agencies. From time-to-time, a surplus of natural gas or oil may occur in areas of the United States. The effect of a surplus may be to reduce the price the partnerships receive for their gas or oil production, or to reduce the amount of natural gas or oil that the partnerships may produce and sell. As a result, the partnership may not be profitable. Lower prices and/or lower production and sales will result in lower revenues for the partnership and a reduction in cash distributions to the partners of that partnership. See "Competition, Markets and Regulation" (page __) for a discussion of the marketing and pricing of natural gas and oil.

Rapid growth of production in the Rocky Mountain region may result in lower prices and production restrictions until new pipeline facilities are put in service. Beginning in 2001 and throughout most of 2002, the Rocky Mountain region, including our Colorado properties, experienced lower prices and occasional curtailments resulting from a local oversupply situation for natural gas. A major pipeline expansion placed in service in May 2003 to move gas from the Rocky Mountain region to Nevada and southern California solved the oversupply problem. However, if production exceeds the additional pipeline capacity, or if producers continue to successfully develop new supplies in the area and if additional pipeline facilities or markets are not developed to utilize or transport the new supplies, the local surplus could continue or reoccur, resulting in lower prices and/or production curtailment and/or higher transport costs and consequently lower net revenues to the partnership, which may cause a reduction of cash distributions to the partners of that partnership.

Environmental hazards involved in drilling gas and oil wells may result in substantial liabilities for the partnership. There are numerous natural hazards involved in the drilling of wells, including unexpected or unusual formations, pressures, blowouts involving possible damages to property and third parties, surface damages, personal injury or loss of life, damage to and loss of equipment, reservoir damage and loss of reserves. Uninsured liabilities would reduce the funds available to a partnership, may result in the loss of partnership properties and may create liability for additional general partners. A partnership may be subject to liability for pollution, abuses of the environment and other similar damages. It is possible that insurance coverage may be insufficient to protect the partnership. In that event, partnership assets would pay personal injury and property damage claims and the costs of controlling blowouts or replacing destroyed equipment rather than for drilling activities. These payments would cause an otherwise profitable partnership to be less profitable or unprofitable and would result in a reduction of cash distributions to the partners of that partnership. See "Proposed Activities – Insurance" (page __) for a discussion of our insurance coverage.

Increases in drilling costs would reduce the partnership's profitability. The oil and gas industryis experiencing rapid cost increases. Increases in the cost of exploration and development affects the ability of the partnerships to acquire additional leases, gas and oil equipment, and supplies and increases the costs and lower the profits of an otherwise profitable partnership. Lower profits results in lower cash distributions to the partners of that partnership.

A reduced availability of drilling rigs, due in part to intense competition in drilling, may delay the drilling of partnership wells and cash distributions to investors. A large number of companies and individuals engage in drilling for natural gas and oil and there is competition for the most desirable leases as well as materials and equipment to drill and complete wells. Increased drilling operations in some areas of the United States have resulted in the decreased availability of drilling rigs and gas/oil field tubular goods. Also, international developments and the possible improved economics of domestic oil and gas exploration may influence others to increase their domestic oil and gas exploration. These factors may reduce the availability of rigs to the partnership resulting in delays in drilling activities. The reduced availability of rigs could delay the partnership in drilling wells on a timely basis and delay the production of natural gas or oil and cash distributions to investors. A delay in drilling could also impact the timing of investors' tax deductions. The competition and increased demand for desirable leases, drilling rigs, and gas/oil field tubular goods could increase the costs of drilling and completing wells. Additional costs could reduce the profitability of a partnership and would result in lower cash distributions to the partners of that partnership. See "Competition, Markets and Regulation – Competition and Markets" (page __) and "Tax Considerations – Intangible Drilling and Development Costs Deductions" (page __) for a discussion of the partnership's competition and the tax implications of drilling wells on a timely basis.

Failure by subcontractors to pay for materials or services could reduce the partnership's profitability. If non-affiliated subcontractors fail to timely pay for materials and services, the wells of the partnerships could be subject to materialmen's and workmen's liens. In that event, the partnerships could incur excess costs in discharging these liens and the profitability of the partnership and the cash distributions to the partners of that partnership would decline.

Delay in partnership gas or oil production could reduce the partnership's profitability. Drilling wells in areas remote from marketing facilities may delay production from those wells until sufficient reserves are established to justify construction of necessary pipelines and production facilities. The partnership's inability to complete wells in a timely fashion may also result in production delays. In addition, marketing demands which tend to be seasonal may reduce or delay production from wells. Wells drilled for the partnerships may have access to only one potential market. Local conditions including but not limited to closing businesses, conservation, shifting population, pipeline maximum operating pressure constraints, and development of local oversupply or deliverability problems could halt or reduce sales from partnership wells. Any of these delays in the production and sale of the partnership's gas and oil could reduce the partnership's profitability, and in that event the cash distributions to the partners of that partnership would decline.

Tax Status and Tax Risks

It is possible that the tax treatment currently available with respect to natural gas and oil exploration and production will change on a retroactive or prospective basis as a result of additional legislative, judicial, or administrative actions. See "Tax Considerations" (page __) and the tax opinion of our tax counsel which we attach as Appendix D to this prospectus for a discussion of the tax implications of an investment in the program.

Partnership classification as a corporation or a publicly traded partnership would substantially alter the tax treatment of the partnership. Tax counsel has rendered its opinion that each partnership will be classified for federal income tax purposes as a partnership and not as a corporation or an association taxable as a corporation or as a "publicly traded partnership" taxable as a corporation. The opinion is not binding on the Internal Revenue Service or the courts. The Service could assert that a partnership should be classified as one of these other structures. If a partnership were so classified, any income, gain, loss, deduction, or credit of the partnership would remain at the entity level, and not flow through to you, the income of the partnership would be subject to corporate tax rates at the entity level and distributions to you may be considered dividend distributions subject to federal income tax at the investor partners' level. See

"Tax Considerations – General Tax Effects of Partnership Structure" (page __) which discusses the tax implications of classification of business entities.

An investment as a limited partner may not be advisable for a person who does not anticipate having substantial current taxable income from passive activities. Net losses generated by the partnership and allocable to a limited partner generally will be subject to the passive activity rules. Under the passive activity rules, passive activity losses of limited partners who are individuals, estates, trusts, and personal service corporations are deductible only to the extent of that limited partner's passive activity income (less restrictive limitations apply to closely held C corporations). Therefore, limited partners may not be able to currently deduct all of the expenses and losses allocated to them from the partnership. See "Tax Considerations – Passive Loss Limitations" (page __) for a discussion of taxation of passive losses.

An investment as an additional general partner in the partnership may not be advisable for a person whose taxable income from all sources is not recurring and is not subject to the higher marginal federal income tax rates. An additional general partner generally will not be subject to the passive activity rules discussed in the previous paragraph. However, the expenses and losses allocated to a partner from the partnership may be used only to offset other taxable income the partner may have. In addition, as mentioned above, an additional general partner could be subject to additional personal liability under West Virginia law. Consequently, to compensate for that additional risk, a person choosing to invest as an additional general partner should ensure that he or she has sufficient current taxable income from all sources (including passive activities) subject to the higher marginal federal income tax rates to offset any expenses and losses allocated from the partnership.

Under the Code, a partner's tax liabilities may exceed the cash distributions received by that partner. Federal income tax payable by you by reason of your distributive share of partnership taxable income for any year may exceed the cash distributed to you by the partnership. You must include in your own return for a taxable year your share of the items of the partnership's income, gain, profit, loss, and deductions for the year, to the extent required under the Internal Revenue Code as then in effect, whether or not cash proceeds are actually distributed to you. For example, income from the partnership's sale of gas production is taxable to you as ordinary income subject to depletion and other deductions; your distributive share of the partnership's taxable income will be taxable to you whether or not the income is actually distributed to you.

If the Service audits the partnership's tax returns, an investor partner might owe more taxes plus interest and penalties. Although the partnerships will not be registered with the Service as "tax shelters," it is possible that the Service will audit each partnership's returns. If audits occur, tax adjustments might be made that would increase the amount of taxes due or increase the risk of audit of your individual tax return. If additional tax is owed, you may also owe interest and penalties in addition to that tax. In addition, costs and expenses may be incurred by a partnership in contesting the adjustments. The cost of responding to audits of your tax return will be borne solely by you. See "Tax Considerations – Administrative Matters" (page __) for a discussion of Service audits of the tax returns of partners of a partnership.

Partnership losses after the conversion of general partnership interests to limited partnership interests will be passive losses for tax purposes. Tax counsel to the Managing General Partner has rendered its opinion that interests in the partnerships held by the additional general partners generally will not be subject to the passive activity rules. However, if an additional general partner interest is converted to a limited partner interest prior to the spudding date, but after the end of the taxable year in which intangible drilling and development costs were incurred, intangible drilling and development costs will be subject to the passive activity rules. In addition, that portion of partnership gross income for the prior taxable year attributable to intangible drilling and development costs treated as passive loss will be considered passive income.

A material portion of the subscription proceeds will not be currently deductible. A material portion of the subscription proceeds of a partnership will be expended for cost and expense items which will not be currently deductible for income tax purposes. See "Tax Considerations – Transaction Fees" (page __) as to the tax treatment of fees incurred by the partnership.

If the Service challenges the partnership's deduction for the prepayment of drilling costs, you could owe additional taxes plus interest and penalties. Some drilling cost expenditures may be made as prepayments during 2005 (with respect to partnerships designated as "PDC 2005- Limited Partnership") and 2006 (with respect to partnerships designated as "PDC 2006- Limited Partnership") for drilling and completion operations which in large part may be performed during 2006 and 2007. All or a portion of these prepayments may be then currently deductible by the applicable partnership if:

the well to which the prepayment relates is spudded within 90 days after December 31, 2005 or 2006, respectively; a well is spudded when a drilling rig begins to drill the hole in the ground.

the payment is not a mere deposit; and

the payment serves a substantial business purpose or otherwise satisfies the clear reflection of income rule.

A partnership could fail to satisfy the requirements for deduction of prepaid intangible drilling and development costs. The Service may challenge the deductibility of these prepayments. If that challenge were successful, you could owe additional taxes plus interest and penalties for years in which the deductions are disallowed. However, the prepaid expenses would be deductible in the tax year in which the services under the drilling contracts are actually performed. See "Tax Considerations – Intangible Drilling and Development Costs Deductions" (page __) for a discussion of the tax treatment of these deductions.

<u>Counsel's tax opinion does not cover various tax considerations involved in one's investment in the partnership</u>. Due to the lack of authority, or the essentially factual nature of the question, tax counsel to the partnership, Duane Morris LLP, has expressed no opinion as to the following:

whether the losses of the partnership will be treated as derived from "activities not engaged in for profit," and therefore nondeductible from other gross income,

whether any of the partnership's properties will be entitled to percentage depletion,

whether any interest incurred by a partner with respect to any borrowings will be deductible or subject to limitations on deductibility,

whether the fees to be paid to us and to third parties will be deductible, and

the impact of an investment in the partnership on an investor's alternative minimum tax.

Various of the above-referenced matters are factual in nature, and the facts are unknown at this time. Therefore, counsel is unable to render an opinion at this time with respect to these matters as to the tax consequences and burdens a taxpayer will likely experience as a result of an investment in the partnership. The facts when they become known with respect to the various matters referred to above may vary from taxpayer to taxpayer and may result in different tax consequences and burdens for individual taxpayers.

You should recognize that an opinion of counsel merely represents counsel's best legal judgment under existing statutes, judicial decisions, and administrative regulations and interpretations. There can be no assurance, however, that some of the deductions claimed by a partnership will not be challenged successfully by the Service.

<u>CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS</u>

This prospectus contains forward-looking statements, including, without limitation, trends impacting the natural gas and oil industry (including prices and market demand), the partnerships' success in drilling and development activities, the expected effect of deregulation and the partnerships' ability to expand their drilling activities geographically, and anticipated tax consequences, that involve risks and uncertainties. The partnerships' actual results and development could differ materially from those discussed or implied in the forward-looking statements as a result of these and other factors. Factors that may cause or contribute to those differences include those discussed under "Risk Factors," "Participation in Costs and Revenues" (page __), "Proposed Activities" (page __), "Competition, Markets and Regulation" (page __), and "Tax Considerations" (page __) as well as those discussed elsewhere in this prospectus. We caution you, however, that this list of factors may not be exhaustive.

TERMS OF THE OFFERING

General

Up to twelve limited partnerships (four in 2004, four in 2005, four in 2006)

Units of general partnership interest and units of limited partnership interest being offered – investor must choose

$20,000 cost per unit

Minimum subscription – $5,000

Minimum partnership – $7,000,000 in subscriptions

Maximum partnership – $70,000,000 in subscriptions

Maximum aggregate subscriptions for twelve partnerships – $400,000,000

Subscription proceeds will be placed in escrow until partnership funded.

PDC 2004-2006 Drilling Program will offer for sale an aggregate of 20,000 Units at $20,000 per unit, aggregating $400,000,000, of preformation interests in a series of up to twelve limited partnerships to be formed under the laws of West Virginia. You may purchase units only if you meet the suitability standards set forth below. We will offer units for sale over a three-year period. We have completed our offering of our first four PDC 2004-designated limited partnership, PDC 2004-A through -D Limited Partnerships and our first two PDC 2005-designated limited partnerships, PDC 2005-A and -B Limited Partnerships, and sold an aggregate of approximately $180 million of the program's securities. Those limited partnerships have been funded and are currently conducting their respective businesses. The managing general partner of each partnership will be Petroleum Development Corporation, a publicly-owned Nevada corporation. We in our discretion may accept subscriptions for less than full units. The minimum subscription is one-quarter unit ($5,000). We will not sell units to tax-exempt investors or to foreign investors.

You may elect to purchase units as an additional general partner or as a limited partner.

Upon the sale of at least the minimum number of units in a partnership (350 units aggregating $7,000,000) with respect to each limited partnership and upon termination of the offering of units in that partnership, we will form a limited partnership under the laws of West Virginia. At that time, the units of preformation general partnership interest and preformation limited partnership interest will become units of general partnership interest and units of limited partnership interest, respectively, in the particular partnership. There is no restriction on the composition of the type of partnership interests with respect to any partnership.

If we do not sell the minimum required aggregate subscription amount of $7,000,000 in the offering of units of any partnership, we will not fund that partnership, and the escrow agent will promptly return all subscription proceeds with respect to that partnership to the respective subscribers in full with any interest earned on the escrowed funds and without any deduction from the escrowed funds. We may not complete a sale of units to any investor until at least five business days after the date the investor has received a final prospectus. In addition, we will send to each investor a confirmation of the purchase.

We will designate the various partnerships as follows. The subscription period for each of the partnerships in our program will be as follows, unless earlier terminated or withdrawn by us:

Partnership	Minimum	Maximum	Planned

Name	Subscription	Subscription	Termination
PDC 2004-A	$3 million	$30 million	May 3, 2004
PDC 2004-B	$1.8 million	$18 million	August 31, 2004
PDC 2004-C	$1.8 million	$18 million	October 31, 2004
PDC 2004-D	$3.5 million	$35 million	December 31, 2004

Each of these partnerships closed and was funded in during 2004. We will not offer or sell any additional securities in any of the above partnerships.

PDC 2005-A	$4 million	$40 million	April 30, 2005
PDC 2005-B	$4 million	$40 million	August 31, 2005
PDC 2005-C	$7 million	$70 million	September 30, 2005
PDC 2005-D	$7 million	$70 million	December 30, 2005

The offerings of PDC 2005-A and -B Limited Partnerships have closed. We will not offer or sell any additional securities in PDC 2005-A or -B Limited Partnerships. These partnerships have been funded and are currently conducting their business operations. We will offer and sell the securities of each of PDC 2005-C and –D Limited Partnerships only during 2005. We may choose not to market the securities of PDC 2005-D Limited Partnership.

PDC 2006-A	$7 million	$70 million	March 31, 2006
PDC 2006-B	$7 million	$70 million	June 30, 2006
PDC 2006-C	$7 million	$70 million	September 30, 2006
PDC 2006-D	$7 million	$70 million	December 29, 2006

We will offer and sell the securities of each of these partnerships only during 2006. We may choose to offer and sell in any of these partnerships less than $70 million of units. If we choose to offer less than the $70 million maximum subscription, we will revise the prospectus to specify the particular ceiling before we begin the particular offering. If we choose to offer for sale units less than the $70 million subscription ceiling with respect to any partnership, we will not lower the required minimum subscription of $7 million for that partnership.

The offering of any particular partnership may extend beyond its anticipated termination date by not more than sixty days or be terminated earlier; however, no offering of partnerships designated "PDC 2004- Limited Partnership," "PDC 2005- Limited Partnership" or "PDC 2006- Limited Partnership" may extend beyond December 31, 2004, 2005, or 2006, respectively.

The offering of units in subsequent partnerships will not commence until the subscription of units in prior partnerships has reached the minimum subscription or that prior offering has terminated.

Once the offering with respect to a particular partnership has closed, we will not offer or sell additional units with respect to that partnership. At or about the time of funding of a particular partnership, we anticipate that we will supplement this prospectus to reflect the results of the offering of that partnership. We will not commence operations of a particular partnership until termination of its offering period.

We will fund each partnership promptly following the termination of its respective offering period, provided that the partnership has reached the minimum subscriptions. We will not fund any partnership beyond December 31, 2004, with respect to partnerships designated "PDC 2004- Limited Partnership," beyond December 30, 2005, with respect to partnerships designated "PDC 2005- Limited Partnership," and beyond December 29, 2006, with respect to partnerships designated "PDC 2006- Limited Partnership."

Subscriptions for units are payable $20,000 in cash per unit purchased upon subscription. Your subscription is not revocable after you submit it to us. Your subscription will continue to be irrevocable during the time your funds are in the escrow account. We will not return your subscription funds to you unless we decide not to complete the offering of the partnership you are investing in. We will place all subscription proceeds of each partnership in a separate interest-bearing escrow account with our escrow agent, Branch Banking and Trust Company ("BB&T"), 223 West Nash Street, Wilson, North Carolina 27893, during the offering period of that partnership. The escrow agreement requires the escrow agent to invest escrowed funds upon receipt and forbids the escrow agent from disbursing funds except upon deposit of checks representing at least the minimum subscriptions and upon written instructions from us and the dealer manager. At that time the escrow agent will disburse the escrowed subscriptions in accordance with these instructions. If we fail to raise the minimum subscriptions, the escrow agent will promptly return the escrowed funds to the subscribers, with any interest earned on the funds and with no deduction from the subscriptions.

The escrow agent will promptly return escrowed subscriptions of partnerships not closed by the sixtieth day following the anticipated offering termination date to the respective investor of that partnership. However, if the offering of units in PDC 2004-C Limited Partnership or PDC 2004-D Limited Partnership (or PDC 2005-C Limited Partnership or PDC 2005-D Limited Partnership; or PDC 2006-C Limited Partnership or PDC 2006-D Limited Partnership, as appropriate) has not closed on or before December 31, 2004 (or 2005 or 2006, as appropriate), the escrow agent will promptly return the escrowed funds of that particular partnership to those investors. The escrow agent will not commingle subscriptions with our funds, nor will subscriptions be subject to the claims of our creditors. The escrow agent will invest subscription proceeds during the offering period only in short-term investments comprised of or secured by securities of the U.S. government. The interest rate on the escrow account is variable. Any income earned on the escrowed funds will be allocated pro rata to the investor partners providing the escrowed funds.

Investors should make their checks for units payable to "BB&T as Escrow Agent for "PDC 2004- Limited Partnership" (or "PDC 2005- Limited Partnership" or "PDC 2006- Limited Partnership," as appropriate) and give their checks to their broker for submission to the dealer manager and escrow agent. All subscription funds received by the selling brokers from investor partners will be transferred by noon of the next business day after receipt to the dealer-manager for transfer to BB&T by noon of the next business day after receipt for deposit into escrow. Your execution of the subscription agreement and its acceptance by us constitute your execution of the limited partnership agreement and your agreement to be bound by the terms of the limited partnership agreement as a partner, including your granting of a special power of attorney to us appointing us as your lawful representative to execute and file a certificate of limited partnership and any amendment of the certificate, governmental reports, certifications, contracts, and other matters.

Activation of the Partnerships

Each partnership will receive funds following termination of offering period.

Each partnership is a separate business and economic entity from each other partnership.

Partnerships will organize under West Virginia law.

We will organize each partnership under the West Virginia Act and each partnership will receive funds promptly following the termination of its offering period. However, we will not fund a partnership with less than the requisite minimum aggregate subscriptions. A partnership will not commence any drilling operations until after its funding.

Each partnership will be a separate and distinct business and economic entity from each other partnership. Thus, as an investor partner, you will be a partner only of that partnership in which you specifically invest and will have no interest in any of the other partnerships (unless you also invest in other partnerships). Therefore, you should consider and rely solely upon the operations and success (or lack of success) of your own partnership in assessing the quality of your investment.

Upon funding of a partnership, we will deposit the subscription funds in that partnership's name in interest-bearing accounts or invest those funds in short-term highly-liquid securities where there is appropriate safety of principal, until the funds are required for partnership purposes. Interest earned on amounts so deposited or invested will be the property of the respective partnership whose funds earned the interest.

We anticipate that within 12 months following the formation of a partnership it will have expended or committed all subscriptions for partnership operations. We will return any unexpended and/or uncommitted subscriptions at the end of the 12-month period pro rata to the investor partners and we will reimburse those partners for organization and offering costs and the management fee allocable to the return of capital. The term "uncommitted capital" will not include amounts set aside for necessary operating capital reserves.

We will file a certificate of limited partnership and any other documents required to form the partnerships with the State of West Virginia and will elect for the partnerships to be governed by the West Virginia Act. We will also take all other actions necessary to qualify the partnerships to do business as limited partnerships or cause the limited partnership status of the partnerships to be recognized in any other jurisdiction where the partnerships conduct business.

Types of Units

Investor may choose to be limited partner or additional general partner.

You may purchase units in a partnership as a limited partner or as an additional general partner. Although investor partners will generally share income, gains, losses, deductions, and cash distributions allocable to them pro rata based upon the amount of their subscriptions, there are material differences in the federal income tax effects and the liability associated with these different types of units. Any income, gain, loss, or deduction attributable to partnership activities will generally be allocable to the partners who bear the economic risk of loss with respect to these activities. Further, additional general partners generally may offset partnership losses and deductions against income from any source. Limited partners generally may offset partnership losses and deductions only against passive income. Income from the partnership will be non-passive for investors who invest as additional general partners, even after their conversion to limited partner status. Investors who invest as limited partners will have passive income. See "Tax Considerations" for a discussion of the tax implications of investing as a limited partner or as an additional general partner.

You may transfer or assign your units of partnership interest in accordance with Section 7.03 of the limited partnership agreement. There will be no market for the units, nor will a public market develop for the units. Transferees seeking to become substituted partners must meet the suitability requirements set forth in this prospectus. A substituted additional general partner will have the same rights and responsibilities, including unlimited liability, in the partnership as every other additional general partner. See "Risk Factors – Additional general partners will be individually liable for partnership obligations and liabilities beyond the amount of their subscriptions, partnership assets, and the assets of the Managing General Partner" for a discussion of the risks of investing as an additional general partner.

You must indicate on the investor signature page of the subscription agreement the number of limited partnership units or general partnership units subscribed for. If you fail to indicate on the subscription agreement a choice between investing as a limited partner or as an additional general partner, we will not accept your subscription but will promptly return the subscription agreement and the tendered subscription funds to you.

Limited Partners. The limited partners will consist of the initial limited partner, Steven R. Williams, one of our executive officers and directors, until the admission of a limited partner to the partnership, and each investor who purchases units of limited partnership interest being offered by this prospectus. The liability of a limited partner of the partnership for the partnership's debts and obligations will not exceed that partner's capital contributions, his or her share of partnership assets, and the return of any part of his or her capital contribution (a) for a period of one year afterwards for the amount of his or her returned contribution if a limited partner has received the return without violation of the limited partnership agreement or the West Virginia Act, but only to the extent necessary to discharge the limited partner's liabilities to creditors who extended credit to the partnership during the period the contribution was held by the partnership and (b) for a period of six years afterwards for the amount of the contribution wrongfully returned if a limited partner has received the return in violation of the limited partnership agreement or the West Virginia Act.

General Partners. The general partners will consist of the managing general partner and each investor purchasing units of general partnership interest. We refer to the investor general partners in this prospectus as "additional general partners." As a general partner of a partnership, each additional general partner will be fully liable for the debts, obligations and liabilities of the partnership individually and as a group with all other general partners as provided by the West Virginia Act to the extent liabilities are not satisfied from the proceeds of insurance, from the indemnification by us, or from the sale of partnership assets. See "Risk Factors – Additional general partners will be individually liable for partnership obligations and liabilities beyond the amount of their subscriptions, partnership assets, and the assets of the Managing General Partner" for a discussion of the risks if you invest as an additional general partner. While the activities of the partnership are covered by substantial insurance policies and indemnification by us which we discuss in this prospectus, it is possible that the additional general partners will incur personal liability (not covered by insurance, partnership assets, or indemnification) as a result of the activities of the partnership.

Conversion of Units by the Managing General Partner and by Additional General Partners.

We will convert all units of general partnership interest into units of limited partnership interest after drilling and completion operations arefinished.

If there is a material change in a partnership's insurance coverage, additional general partners may convert prior to the change.

Liability for investors will be limited after conversion.

We will convert all units of additional general partnership interest of a particular partnership into units of limited partnership interest when drilling and completion operations of that partnership are finished. Additional general partners may also convert their interests into limited partnership interests at any time within the 30 day period prior to any material change in the amount of the partnership's insurance coverage. Upon conversion they will become limited partners of that partnership. Effecting conversion is subject to the express requirements that the conversion will not cause a termination of the partnership for federal income tax purposes and that the additional general partner provides written notice to us of the intent to convert.

Conversion of an additional general partner to a limited partner in a particular partnership will be effective upon our filing with the State of West Virginia an amendment to the Certificate of Limited Partnership. We are obligated to file an amendment to the Certificate at any time during the full calendar month after receipt by us of the required notice of the additional general partner, provided that the conversion will not constitute a termination of the partnership for tax purposes. A conversion made in response to a material change in that partnership's insurance coverage will be effective prior to the effective date of the change in insurance coverage. After the conversion of a partner's general partnership interest to that of a limited partner, each converting additional general partner will continue to have unlimited liability regarding partnership liabilities arising prior to the effective date of the conversion, but will have limited liability to the same extent as limited partners after conversion to limited partner status is effected. If a taxpayer has any loss from any taxable year from a working interest in any oil or gas property that is treated as a non-passive loss, then any net income from the property for any succeeding taxable year is to be treated as income that is not from a passive activity. Consequently, assuming that a converting additional general partner has losses from working interests which are treated as non-passive, income from the partnership allocable to the partner after conversion would be treated as income that is not from a passive activity. See page __ under the heading "Tax Considerations – Conversion of Interests" for an explanation of the tax considerations regarding a conversion of an additional general partner interest to a limited partner interest.

We are not entitled to convert our interests into limited partnership interests. Limited partners do not have any right to convert their units into units of general partnership interest. In the event additional general partners desire to convert to limited partners due to a loss of insurance coverage, the partnership will cease drilling activities until all desired conversions can be made.

Unit Repurchase Program

You may request us to repurchase your units at any time beginning with the third anniversary of the first cash distribution of the particular partnership.

You may, at your election, sell your units to the Managing General Partner for not less than four times the most recent twelve months' cash distributions from production.

If requested by investors, the Managing General Partner is obligated to purchase in any calendar year units which aggregate up to 10% of the initial subscriptions, subject to its financial ability to do so

Beginning with the third anniversary of the date of the first cash distribution of the particular partnership, you may request us to repurchase your units. If requested by investors and subject to the available borrowing capacity under our loan agreements to effect repurchases and the opinion of counsel referred to below, each year we will be obligated to repurchase for cash up to 10% of the units originally subscribed to in the particular partnership. Our obligation to purchase units may, however, be conditioned on counsel's determination that the repurchases of a particular investor partner's units will not result in the termination of the partnership for federal income tax purposes. It is possible that repurchases of units could result in the units being "readily tradable on a secondary market or the substantial equivalent thereof," Code Section 7704(b)(2), the result of which the partnership could be deemed to be a "publicly-traded partnership." To limit the possibility of this characterization, we may require receipt of counsel's opinion.

We will not favor one particular partnership over another in the repurchase of units. We will extend the right to request equally to all interest holders participating in an individual partnership, excluding interests held by us. Notwithstanding the preceding sentence, if investor partners request the repurchase of more than 10% of the units of a partnership or more units than we are able to purchase, we will purchase units on a "first-come, first-served" basis based on date of receipt by us of a letter of acceptance of the repurchase right from the investor partner. If we are unable to repurchase all units requested for repurchase, because of limitations imposed by this unit repurchase program or by the Code or due to insufficient borrowing capacity under any loan banking agreement(s) to which we may be a party, a requesting investor partner will be entitled to have his or her units repurchased on a "first-come, first-served" basis, regardless of partnership, provided that the repurchase of a particular investor partner's units will not have the effect of causing termination of his or her partnership for tax purposes or of causing the partnership to be treated as a "publicly traded partnership." If we are unable to repurchase all units requested for repurchase at the same time by partners of any partnership, we will repurchase those particular units on a pro rata basis.

In order to initiate the process in which we will repurchase your units, you must provide us written notification of your intention to have us purchase your units. We will provide you a written notice of a specified price for purchase of the particular units within 30 days of our receipt of your written notification. Within 60 days following your receipt of the repurchase price established by us, you, if in fact you elect to accept the repurchase price, need to notify us in writing that the price is acceptable. We will promptly mail you a check for the proceeds of the purchase.

The minimum repurchase price which we may make will be a cash amount equal to not less than four times cash distributions from production of that particular partnership for the twelve months prior to the month preceding the date upon which we have received the written notification referred to above. We may, in our sole and absolute discretion, increase the repurchase price for units to be repurchased.

A repurchase price established by us may not represent the fair market value of the units. In setting the price, we will consider our available funds and our desire to acquire production as represented by the unit and will take into account what we perceive to be our own best interests as a publicly-owned company. **You are free to accept or not to accept the price that we set; you are in no way obligated to**

accept our price. We will provide you with detailed information as to how we calculated our price. We will also provide each interest holder with a calculation of the valuation of his or her interest, based on the most recent reserve evaluation prepared by an independent expert in accordance with SEC Regulation S-X, Article 4, Rule 4-10. This calculation will take into account our best estimate of anticipated production declines or increases, known price increases or decreases, operating, recompletion and plugging costs, and other relevant factors. When a well is unsuccessful, or when it has produced as much oil and gas as it can produce profitably, it must be plugged. Plugging a well requires that the well be filled partially or completely with cement so that any remaining oil or gas is trapped in the producing zone so it cannot leak to pollute the environment or create a safety hazard.

To date, approximately 1,455 units (out of approximately 16,130 eligible units) of prior programs sponsored by us have been presented under the respective unit repurchase programs (which are the same as that of the partnership) for repurchase at prices ranging from 3 to 4 times the most recent 12 month cash distributions. Programs that we sponsored before 1998 provided for a three times cash distribution minimum offer price. The 16,130 units include all partnerships through and including PDC 2001-C Limited Partnership. More recent programs had not satisfied the three-year holding period. The figures reflect all partnerships formed by us from 1984 through November 2001.

Investor Suitability

Investment in the units involves a high degree of risk.

You may invest only if you are qualified to purchase units.

Investment is suitable only for investors having substantial financial resources who understand the long-term nature, tax consequences, and risk factors associated with this investment.

Minimum requirements are $225,000 net worth, or a net worth of $60,000 and taxable income of $60,000.

States with more stringent requirements are set forth below.

Transferees of units must meet the suitability requirements set forth in this section.

Tax-exempt investors and foreign investors may not purchase units.

Because an investment in the units involves a high degree of risk and is intended by us to be a long-term investment by you, it is suitable for you **only** if you have adequate financial means, have no immediate need for liquidity in your investment and can bear the complete loss of your investment in the units.

It is the obligation of persons selling units to make every reasonable effort to assure that the units are suitable for investors, based on the investor's investment objectives and financial situation, regardless of the investor's income or net worth. We will not sell units to tax-exempt investors or to foreign investors.

We will sell units, including fractional units, to you only if you satisfy the following suitability requirements. Net worth will be determined exclusive of home, home furnishings and automobiles. In addition, we will sell units to you only if you make a written representation that you are the sole and true party in interest and that you are not purchasing for the benefit of any other person (or that you are purchasing for another person who meets all of the conditions set forth in this section).

The following represent footnotes to various states set forth in the two following tables. Please refer to the following footnotes as appropriate.

(X) California residents generally may not transfer units without the consent of the California Commissioner of Corporations.

(Y) Michigan, Missouri, New Mexico, Ohio, Pennsylvania, and South Dakota investors may not invest if the dollar amount of their investment is equal to or more than 10% of their net worth.

Purchasers of Units of Limited Partnership Interest. If you wish to purchase units of limited partnership interest in the partnership, you must satisfy the following suitability requirements for your state of residence, as summarized in the following table and accompanying footnotes, including those footnotes that precede this section.

State	Requirement	State	Requirement	State	Requirement
AK	2	MO	5 (Y)	OK OR	1
AL AR AZ	1	MT	1	PA	6 (Y)
CA	4 (X)	NC	5	RI SC	1
CO CT DC DE	1	ND NE	1	SD	6 (Y)
FL GA HI IA	1	NH	3	TN TX UT VA	1
ID IL IN KS	1	NJ	1	VT WA WI WV	1
KY LA MA MD	1	NM	1 (Y)	WY	1
ME MN MS	1	NV NY	1		
MI	5 (Y)	OH	1 (Y)		

The following footnotes relate to the corresponding numbers in the table above.

You must have a minimum net worth of $225,000 or a minimum net worth of $60,000 and had during the last tax year or estimate that you will have during the current tax year "taxable income" as defined in Section 63 of the Code of at least $60,000 without regard to an investment in units.

You must be a person whose total purchase does not exceed 5% of your net worth if the purchase of securities is at least $10,000, and have either: (a) a minimum annual gross income of $60,000 and a minimum net worth of $60,000, exclusive of principal automobile, principal residence, and home furnishings, or (b) a minimum net worth of $225,000, exclusive of principal automobile, principal residence, and home furnishings.

You must have either: (a) a net worth of not less than $250,000 (exclusive of home, furnishings, and automobiles), or (b) a net worth of not less than $125,000 (exclusive of home, furnishings, and automobiles), and $50,000 in taxable income.

You must (a) have net worth of not less than $250,000 (exclusive of home, furnishings, and automobiles) and expect to have gross income in 2004 (with respect to the PDC 2004 designated partnerships) or in 2005 (with respect to the PDC 2005 designated partnerships) or in 2006 (with respect to the PDC 2006 designated partnerships) of $65,000 or more, or (b) have net worth of not less than $500,000 (exclusive of home, furnishings, and automobiles), or (c) have net worth of not less than $1,000,000, or (d) expect to have gross income in 2004 (with respect to the PDC 2004 designated partnerships) or in 2005 (with respect to the PDC 2005 designated partnerships) or in 2006 (with respect to the PDC 2006 designated partnerships) of not less than $200,000.

You must have (a) a net worth of not less than $225,000 (exclusive of home, furnishings, and automobiles), or (b) a net worth of not less than $60,000 (exclusive of home, furnishings, and automobiles) and estimated 2004 (with respect to investments in the PDC 2004 designated partnerships; or 2005 with respect to investments in the PDC 2005 designated partnerships; or 2006 with respect to investments in the PDC 2006 designated partnerships) taxable income as defined in Section 63 of the Internal Revenue Code of 1986 of $60,000 or more without regard to an investment in a partnership.

You must have either: (a) a net worth of at least $225,000 (exclusive of home, furnishings, and automobiles); or (b) a net worth of at least $60,000 (exclusive of home, furnishings, and automobiles) and taxable income, as defined in Section 63 of the Code, of $60,000 or more in 2003 (for the PDC 2004 designated partnerships; in 2004 for the PDC 2005 designated partnerships; or in 2005 for the PDC 2006 designated partnerships), or estimate that your 2004 (for the PDC 2004 designated partnerships; 2005 for the PDC 2005 partnerships; or 2006 for the PDC 2006 designated partnerships) taxable income, as defined in Section 63 of the Code, will be $60,000 or more, without regard to the investment in the program; or (c) that you are purchasing in a fiduciary capacity for a person or entity who satisfies the requirements of (a) or (b).

Purchasers of Units of General Partnership Interest. If you wish to purchase units of general partnership interest in the partnership, you must satisfy the following suitability requirements for your state of residence, as summarized in the following table and accompanying footnotes, including those footnotes that precede this section set forth above under "Investor Suitability."

State	Requirement	State	Requirement	State	Requirement
AK	2	MD	1	OH	4 (Y)
AL AR	4	ME MN MS	4	OK	4
AZ	5	MI	5 (Y)	OR	5
CA	6 (X)	MO	4 (Y)	PA	4 (Y)
CO CT DC DE	1	MT	1	RI SC	1
FL GA HI	1	NC	4	SD	7 (Y)
IA	5	ND NE	1	TN TX	4
ID IL	1	NH	3	UT VA	1
IN KS KY	5	NJ	1	VT WA	5
LA	1	NM	5 (Y)	WI WV WY	1
MA	4	NV NY	1		

The following footnotes relate to the corresponding numbers in the table above.

1. You must have a minimum net worth of $225,000 or a minimum net worth of $60,000 and had during the last tax year or estimate that you will have during the current tax year "taxable income" as defined in Section 63 of the Code of at least $60,000 without regard to an investment in units.

You must be a person whose total purchase does not exceed 5% of your net worth if the purchase of securities is at least $10,000, and have either: (a) a minimum annual gross income of $60,000 and a minimum net worth of $60,000, exclusive of principal automobile, principal residence, and home furnishings, or (b) a minimum net worth of $225,000, exclusive of principal automobile, principal residence, and home furnishings.

You must have either: (a) a net worth of not less than $250,000 (exclusive of home, furnishings, and automobiles), or (b) a net worth of not less than $125,000 (exclusive of home, furnishings, and automobiles), and $50,000 in taxable income.

You must have (a) an individual or joint minimum net worth (exclusive of home, home furnishings and automobiles) with your spouse of $225,000, without regard to the investment in the program and a combined minimum gross income of $100,000 or more for the current year and for the two previous years; or (b) an individual or joint minimum net worth with your spouse in excess of $1,000,000, inclusive of home, home furnishings and automobiles; or (c) an individual or joint minimum net worth with your spouse in excess of $500,000, exclusive of home, home furnishings and automobiles; or (d) a combined minimum gross income in excess of $200,000 in the current year and the two previous years.

You must have (a) an individual or joint minimum net worth (exclusive of home, home furnishings, and automobiles) with your spouse of $225,000, without regard to an investment in the program, and an individual or combined taxable income of $60,000 or more for the previous year and an expectation of an individual or combined taxable income of $60,000 or more for each of the current year and the succeeding year; or (b) an individual or joint minimum net worth with your spouse in excess of $1,000,000, inclusive of home, home furnishings and automobiles; or (c) an individual or joint minimum net worth with your spouse in excess of $500,000, exclusive of home, home furnishings and automobiles; or (d) a combined minimum gross income in excess of $200,000 in the current year and the two previous years.

You must (a) have net worth of not less than $250,000 (exclusive of home, furnishings, and automobiles) and expect to have gross income in 2004 (with respect to the PDC 2004 designated partnerships) or in 2005 (with respect to the PDC 2005 designated partnerships) or in 2006 (with respect to the PDC 2006 designated partnerships) of $120,000 or more, or (b) have net worth of not less than $500,000 (exclusive of home, furnishings, and automobiles), or (c) have net worth of not less than $1,000,000, or (d) expect to have gross income in 2004 (with respect to the PDC 2004 designated partnerships) or in 2005 (with respect to the PDC 2005 designated partnerships) or in 2006 (with respect to the PDC 2006 designated partnerships) of not less than $200,000.

You must have (a) an individual or joint minimum net worth (exclusive of home, home furnishings, and automobiles) with your spouse of $225,000, without regard to an investment in the program, and an individual or combined taxable income of $60,000 or more for the previous year and an expectation of an individual or combined taxable income of $60,000 or more for each of the current year and the succeeding year; or (b) an individual or joint minimum net worth with your spouse in excess of $1,000,000 (inclusive of home, home furnishings and automobiles); or (c) an individual income in excess of $200,000 in each of the two most recent years or joint income with your spouse in excess of $300,000 in each of those years and have a reasonable expectation of reaching the same income level in the current year.

Miscellaneous. Transferees of units seeking to become substituted partners must also meet the suitability requirements discussed above, as well as the requirements imposed by the limited partnership agreement, including transfers of units by a partner to a dependent or to a trust for the benefit of a dependent or transfers by will, gift or by the laws of descent and distribution.

If you purchase units in a fiduciary capacity for any other person (or for an entity in which you are deemed to be a "purchaser" of the subject units), all of the suitability standards set forth above will be applicable to that other person.

You are required to execute your own subscription agreements. We will not accept any subscription agreement that has been executed by someone other than you or in the case of fiduciary accounts by someone who does not have the legal power of attorney to sign on your behalf.

For details regarding how to subscribe, see "Special Subscription Instructions" which we attach as Appendix C.

ASSESSMENTS AND FINANCING

The units of the partnerships are not subject to assessments.

Operations for drilling wells by the particular partnerships will be funded through subscription proceeds and capital contributed to the partnerships by the Managing General Partner. Over the term of a partnership, additional funds might be necessary to complete that partnership's activities.

The partnership may borrow funds on behalf of the partnership for partnership activities from the Managing General Partner or affiliates of the Managing General Partner or from unaffiliated persons.

We intend to develop a particular partnership's interests in its prospects only with the proceeds of subscriptions and our capital contributions. However, these funds may not be sufficient to fund all costs, and it may be necessary for a partnership to retain partnership revenues for the payment of these costs, or for us to advance the necessary funds to a partnership or for the partnership to borrow necessary funds. It is likely that the partnership's Wattenberg Field, Colorado wells will need recompletion services, generally in five to seven years following initial drilling of those wells. Recompletion is the process of going into an existing producing well to complete the well in a new zone at a different depth, or to retreat the zone which is already producing, with the objective of increasing the production of oil or gas. If we retain partnership revenues for the payment of these development costs, the amount of partnership funds available for distribution to the partners of that partnership will decrease correspondingly. We will not drill any wells beyond the initial wells. Additional development refers to work necessary or desirable to enhance production from existing wells. We will retain payment for the development work from partnership proceeds in one of two methods:

- We will prepare an authority for expenditures (an "AFE") estimate for the partnership. The operator will complete the development work and will bill the partnership for the work performed; or

- We will prepare an authority for expenditures estimate for the partnership. The partnership will retain revenues from operations until it has accumulated sufficient funds to pay for the development work, at which time the operator will commence the work, and we will pay the operator as the work progresses.

The choice of which option to use will be at our discretion, based on the amount of the anticipated expenditure and the urgency of the necessary work.

The limited partnership agreement permits the partnership to borrow funds on behalf of the partnershipfor partnership activities. See Section 6.03(a) of the limited partnership agreement. The partnership may borrow needed funds, or receive advances, from the Managing General Partner or affiliates of the Managing General Partner or from unaffiliated persons. On loans or advances made available to the partnership by the Managing General Partner or affiliates of the Managing General Partner, the Managing General Partner or affiliate may not receive interest in excess of its interest costs, nor may the Managing General Partner or affiliate receive interest in excess of the amounts which would be charged the partnership (without reference to the Managing General Partner's financial abilities or guarantees) by unrelated banks on comparable loans for the same purpose.

SOURCE OF FUNDS AND USE OF PROCEEDS

Source of Funds

Upon completion of the offering, the sole funds available to each partnership will be the contributions of the investor partners ($7,000,000 ranging to $70,000,000 for each of the Limited Partnerships) and our contribution in cash equal to 24.4% of the aggregate subscriptions of the investor partners ($1,711,111 ranging to $17,111,111 for each of the Limited Partnerships) for a total amount of partnership capital equaling $8,711,111 for sale of the minimum 350 units ranging to $87,111,111 for sale of the maximum 3,500 units. See the table presented below under "Use of Proceeds" for the amounts of capital available to the partnerships after deduction of brokerage-related expenses and the one-time management fee.

Use of Proceeds

The following table presents information respecting the financing of a partnership inboth the minimum and maximum subscription circumstances:

The sale of 350 units ($7,000,000), the minimum number of units for each partnership;

The sale of 3,500 units ($70,000,000), the maximum number of units for each partnership.

In the table below, the percentages presented are based upon the total of the investor partners' capital contributions and our capital contribution in cash. Each of the partnerships may sell a maximum of 3,500 units ($70,000,000) and must sell a minimum of 350 units ($7,000,000) for the particular partnership to close and be funded. We may choose to set a lower maximum subscription with respect to any of our remaining limited partnerships; we will revise our prospectus if we set a lower maximum subscription ceiling and that will occur before we commence the offering of a future partnership. If we set a lower maximum subscription ceiling, we will not change the minimum subscription amount of $7,000,000 with respect to that partnership.

The following table reflects that PDC Securities Incorporated, the dealer-manager of the program and our affiliate, will receive and may reallow in whole or in part up to a maximum of $7,350,000 for each partnership with respect to the sale of the maximum 3,500 units by each partnership ranging to $735,000 for the sale of the minimum of 350 units for each partnership for sales commissions, reimbursement of due diligence expenses, marketing support fees and other compensation payable to other NASD-licensed broker-dealers in connection with the sale of the units. Of these amounts, in lieu of reimbursement of specific expenses, PDC Securities will retain 2% of subscriptions for wholesaling fees and expenses, meeting costs and other selling expenses; these fees will range from $140,000 for the sale of the minimum number of 350 units for each partnership, ranging to $1,400,000 for the sale of the maximum number of 3,500 units with respect to each partnership. These payments will be made solely in cash on the amount of initial subscriptions.

The table also reflects that we will pay organization and offering costs in excess of 10½% of subscriptions, without recourse to the partnership. The percentage column that appears in the following table relates to the two columns that precede it.

We will disburse substantially all of the funds available to the partnership for the following purposes and in the following manner:

	350 Units Sold	Units Sold	%
Total Partnership Capital	$8,711,111	$87,111,111	100.0%
LESS: Public offering expenses, dealer manager's fee and sales commission	735,000	7,350,000	8.4%
LESS: Management fee to managing general partner	105,000	1,050,000	1.2%
Amount available for investment	$7,871,111	$78,711,111	90.4%

Subsequent Source of Funds

We will commit or expend substantially all of the partnership's initial capital following the offering. We anticipate that the partnership wells that we drill in the Wattenberg Field in Colorado will need recompletion services following initial drilling so that these wells might be their most productive. We anticipate that we will commence recompletion activities approximately five years following our completion of initial drilling of the partnership's wells. Recompletion services, which currently cost approximately $125,000 per well, will require significant additional funding by the partnership. The limited partnership agreement permits the partnership to borrow funds for its activities. The partnership may borrow funds from the Managing General Partner or affiliates of the Managing General Partner or from unaffiliated persons. Consequently, borrowed funds and funds from partnership production may be used to satisfy any future requirements for additional capital. See "Risk Factors – A partnership may borrow funds if needed for partnership operations to fully develop the partnership's wells; if full development of the partnership's wells proves commercially unsuccessful, an investor might anticipate a reduction in cash distributions" for a discussion of the risks involved as a result of the ability of the partnership to borrow funds.

PARTICIPATION IN COSTS AND REVENUES

Profits and Losses; Cash Distributions

The limited partnership agreement provides for the allocation of profits and losses during the production phase of a particular partnership and for the distribution of cash available for distribution between investor partners and us, as follows:

	Investor Partners	Managing General Partner
Throughout term of Partnership	75%	25%

The allocations and distributions to the investor partners and to us may vary during the ten years of partnership well operations commencing six months after the close of a partnership for any partnership that fails to meet the partnership's performance standard. See "Revenues – Revision to Sharing Arrangements," immediately below. Additionally, if we must increase our capital contribution above our required cash investment of 24.4% of subscriptions to cover tangible drilling and lease costs, our share of profits and losses and cash available for distribution will increase to equal our percentage share of the total well costs, excluding the Managing General Partner's drilling compensation, and the investor partners' share will correspondingly decrease. See "Costs – Lease Costs, Tangible Well Costs, and Gathering Line Costs," below for a discussion of the allocations of the costs of the partnership.

Revision to Sharing Arrangements. The limited partnership agreement provides for the allocation of partnership profits and losses 75% to the investor partners and 25% to us throughout the term of each partnership. However, amounts will be paid to the partners only *after* payment of fees and expenses to the Managing General Partner and its affiliates and *only* if there is sufficient cash available. The limited partnership agreement provides for the enhancement of investor cash distributions if the particular partnership does not meet the performance standard described below during the ten-year period commencing eight months after the close of that partnership and ending ten years later.

The performance standard is as follows: If the average annual rate of return, as defined below, to the investor partners is less than 12.5% of their subscriptions, the allocation rate of all items of profit and loss and cash available for distribution for investor partners will increase by ten percentage points above the then-current sharing arrangements for investor partners and the allocation rate with respect to those items for the Managing General Partner will decrease by ten percentage points below the then-current sharing arrangements for the Managing General Partner, until the average annual rate of return increases to 12.5% or more, or until ten years and eight months from the closing date of the partnership expire, whichever event shall occur sooner. "Average annual rate of return" for purposes of this preferred sharing arrangement means (1) the sum of cash distributions and estimated initial tax savings of 25% of investor subscriptions, realized for a $10,000 investment in the partnership, divided by (2) $10,000 multiplied by the number of years (less eight months) which have elapsed since the closing of the partnership. To the extent that the sharing arrangements change in any particular year as a result of this performance standard, the allocations of revenues to the investor partners will increase accordingly and the allocation of revenues to the Managing General Partner will correspondingly decrease. **The above-referenced revised sharing arrangement policy is not, and no investor should consider the policy to be, any form of guarantee or assurance of a rate of return on an investment in the partnership. The policy is the result of a contractual agreement by us as set forth in § 4.02 of the limited partnership agreement. There is no guarantee or assurance whatsoever that the partnership will drill commercially successful gas or oil wells or that the cash distributions to the partners, including any cash distributions under the policy, will achieve a 12.5% rate of return.**

Example: It has been 5 years and 8 months since a partnership was closed. Investors have received cash distributions equal to 30% of their initial subscription. What is the status of the preferred return?

To determine the status of the preferred return, you add the estimated initial tax savings of 25% and the 30% cash return for a total of 55%. Five years and eight months have elapsed since the partnership closed, so we subtract eight months to find the number of years to use to determine the average annual return (5 years 8 months less 8 months equals 5 years). Finally, divide the total return by the 5-year period to determine average annual rate of return (55% ÷ 5 years = 11% per year). The 11% per year is less than the 12.5% per year requirement, and as a result the investor partners will share 85% of the cash available for distribution, and the Managing General Partner will receive 15%.

The foregoing allocation of profits and losses is an allocation of each item of income, gain, loss, and deduction which, in the aggregate, constitute a profit or a loss.

Revenues

Natural Gas and Oil Revenues; Sales Proceeds. The limited partnership agreement provides for the allocation of revenues from natural gas and oil production and gain or loss from the sale or other disposition of productive wells and leases 75% to the investor partners and 25% to us. The production revenues to be allocated are subject to "Revision to Sharing Arrangements," immediately above, and to revisions due to increases in our capital contributions to cover tangible drilling and lease costs, as disclosed below under "Lease Costs, Tangible Well Costs, and Gathering Line Costs."

Interest Income. We will credit to the investor partners 100% of any interest earned on the deposit of subscription funds prior to the closing of the offering and funding of the respective partnership. We will allocate and credit interest earned on the deposit of operating revenues and revenues from any other sources in the same percentages that oil and gas revenues are then being allocated to the investor partners and us.

Sale of Equipment. We will allocate all revenues from sales of equipment in the same percentages as oil and gas revenues are then being allocated.

Sale of Productive Properties. In the event of the sale or other disposition of a productive well, a lease upon which the well is situated, or any equipment related to that lease or well, we will allocate and credit to the investor partners and us the gain from the sale or disposition in the same percentages as oil and gas revenues are then being allocated. The term "proceeds" above does not include revenues from a royalty, overriding royalty, lease interest reserved, or other promotional consideration reserved by a partnership in connection with any sale or disposition. We will allocate these revenues to the investor partners and us in the same percentages as allocation of oil and gas revenues.

Costs

Organization and Offering Costs. We, and not the partnership, will pay organization and offering costs, net of the dealer manager commissions, discounts and due diligence expenses, and wholesaling fees, of the partnerships. We will pay all legal, accounting, printing, and filing fees associated with the organization of the partnerships and the offerings of units. We will allocate to us 100% of these costs. The investor partners will pay all dealer manager commissions, discounts, and due diligence reimbursement and will be allocated 100% of these costs. However, we will allocate and charge to us 100% of organization and offering costs in excess of 10½% of subscriptions.

Management Fee. We will allocate the nonrecurring management fee 100% to the investor partners and 0% to us. The one-time management fee will equal 1½% of the total subscriptions and is payable to the Managing General Partner upon closing of the particular partnership.

Lease Costs, Tangible Well Costs, and Gathering Line Costs. We will allocate the costs of leases, tangible well costs and gathering line costs 0% to the investor partners and 100% to us.

We will contribute and/or pay for the partnership's share of all leases, tangible drilling and completion costs, and gathering line costs. If these costs exceed our requiredcapital contribution, we will increase our capital contribution. **In that event, our share of all items of profit and loss during the production phase of operations and cash available for distribution would be modified to equal for us the percentage arrived at by dividing our capital contributions by the total well costs, excluding the**

Managing General Partner’s drilling compensation; the investor partners' allocations of these items would be changed accordingly.

Intangible Drilling Costs. Intangible drilling costs are costs required to drill a well and prepare the well for production. These costs have no salvage value. Items like the cost of drilling the well, the cost of grading the surface, labor costs, and geological costs associated with selecting a well site are intangible well costs. The cost of production equipment, casing pipe, and other equipment are tangible costs because it may be possible to remove them from a depleted or unsuccessful well and sell them or use them somewhere else. We will allocate intangible drilling costs and recapture of intangible drilling costs in proportion to the investor partners' and our respective payment of intangible drilling costs. Recapture, if any, attributable to intangible drilling and development costs will be allocable on the same percentage basis as the allocation of intangible drilling and development costs. Recapture means that you must include the income you receive for the sale of partnership interest as part of your regular taxable income to the extent the sales price exceeds your partnership tax basis, rather than as long-term capital gains. Regular income is generally taxed at a higher rater than long-term capital gains.

Investor partners' portion of capital available for investment will pay the intangible expenses, including the Managing General Partner’s drilling compensation of 15% of the total cost of the partnership’s wells. The entire capital contribution of the investor partners, after payment of brokerage commissions, due diligence reimbursement, and the management fee, will be utilized to pay for IDC. If the capital contributions of the investor partners are insufficient to pay the intangible drilling costs, we will pay the additional amount of these costs, and in these circumstances the sharing arrangements for intangible drilling costs and recapture of intangible drilling costs will be in proportion to the investor partners' and our respective payment of intangible drilling costs.

Operating Costs. Operating costs are the costs at the well level associated with producing and maintaining productive wells, like well tending charges, painting equipment and maintaining access roads. We will allocate and charge operating costs of partnership wells 75% to the investor partners and 25% to us, subject to revision in the event of the preferred return and/or our increased investment, as we have discussed in this section.

Direct Costs. Direct costs are partnership level costs, primarily independent auditor and reserve engineer fees and tax preparation. We will allocate and charge direct costs of the partnerships 75% to the investor partners and 25% to us, subject to revision in the event of the preferred return and/or our increased investment, as we have discussed in this section.

Administrative Costs. We will allocate 100% of the administrative costs of the partnerships to us.

The table below summarizes the participation of the investor partners and us, taking account of our capital contribution, in the costs and revenues of the partnerships. See "Glossary of Terms," "Participation in Costs and Revenues," and the limited partnership agreement, Appendix A to this prospectus.

With regard to the table below, we, without recourse to the partnerships, will pay organization and offering costs in excess of 10½% of subscriptions. The "Direct Costs" line item represents operating costs incurred after the completion of productive wells, including monthly per-well charges paid to us. We will receive monthly reimbursement from the partnerships for their direct costs incurred by us on behalf of the partnerships.

	Investor Partners	**Managing General Partner**
Partnership Costs		
Broker-dealer Commissions and Expenses	100%	0%
Management Fee	100%	0%
Undeveloped Lease Costs	0%	100%
Tangible Well Costs	0%	100%
Intangible Drilling and Development Costs	100%	0%

Managing General Partner's Drilling Compensation	100%	0%
Drilling and Completion Costs, excluding Managing General Partner's Drilling Compensation	75%	25%
Operating Costs	75%	25%
Direct Costs	75%	25%
Administrative Costs	0%	100%
Partnership Revenues		
Sale of Oil and Gas Production (1)	75%	25%
Sale of Productive Properties (1)	75%	25%
Sale of Equipment	75%	25%
Sale of Undeveloped Leases (1)	75%	25%
Interest Income (1)	75%	25%

(1) The allocation of these partnership revenues is subject to revision. See "Revision to Sharing Arrangements" and "Lease Costs, Tangible Well Costs, and Gathering Line Costs," above.

We estimate that direct costs allocable to the investor partners for the initial 12 months of their operations will be approximately $27,000 if minimum subscriptions ($7,000,000) are received (representing .39% of aggregate partnership capital), and approximately $440,000 if maximum subscriptions ($400,000,000) are received (representing 0.11% of aggregate partnership capital). The following table sets forth the components of these estimated charges to the investor partners during the first year after a partnership is formed, assuming the minimum and maximum subscriptions are obtained:

	Minimum Subscriptions (350 Units)	Maximum Subscriptions (20,000 Units)
Administrative Costs:		
Printing, Shipping and Other Costs	$75,000	$320,000
Total Administrative Costs	$75,000	$320,000
Direct Costs:		
Audit and Tax Preparation	$15,000	$180,000
Independent Engineering Reports	8,000	200,000
Materials, Supplies and Other	4,000	60,000
Total Direct Costs	$27,000	$440,000

We will bear all administrative costs of the partnerships.

The following table presents for each partnership formed by us in the last three years the dollar amount of direct costs and administrative costs incurred by the particular partnership in each year and the percentage of subscriptions raised reflected by those costs.

	2004					
Partnership Name	Amount	% of Subscriptions	Amount	% of Subscriptions	Amount	% of Subscriptions
PDC 2002-A	$12,133	0.17%	$ 8,286	0.12%	$ 7,635	0.11%
PDC 2002-B	13,546	0.12%	12,220	0.11%	11,100	0.10%
PDC 2002-C	12,784	0.14%	10,691	0.11%	15,064	0.16%
PDC 2002-D	19,017	0.07%	27,653	0.10%	28,051	0.10%
PDC 2003-A	-	-	11,703	0.14%	13,075	0.15%
PDC 2003-B	-	-	17,365	0.10%	17,181	0.10%
PDC 2003-C	-	-	16,995	0.10%	14,040	0.08%
PDC 2003-D	-	-	19,321	0.06%	24,946	0.07%

PDC 2004-A	-	-	-	-	27,562	0.09%
PDC 2004-B	-	-	-	-	16,949	0.09%
PDC 2004-C	-	-	-	-	17,055	0.09%
PDC 2004-D	-	-	-	-	19,405	0.06%

Administrative Costs

	2002		2003		2004	
Partnership Name	Amount	% of Subscriptions	Amount	% of Subscriptions	Amount	% of Subscriptions
PDC 2002-A	$ 70,373	0.99%	-	-	-	-
PDC 2002-B	110,066	0.99%	-	-	-	-
PDC 2002-C	92,935	0.99%	-	-	-	-
PDC 2002-D	286,530	0.99%	-	-	-	-
PDC 2003-A	-	-	$86,703	1.02%	-	-
PDC 2003-B	-	-	177,165	1.02%	-	-
PDC 2003-C	-	-	178,445	1.02%	-	-
PDC 2003-D	-	-	357,530	1.02%	-	-
PDC 2004-A	-	-	-	-	$240,235	0.83%
PDC 2004-B	-	-	-	-	148,875	0.83%
PDC 2004-C	-	-	-	-	148,875	0.83%
PDC 2004-D	-	-	-	-	289,557	0.83%

Allocations Among Investor Partners; Deficit Capital Account Balances

We will allocate the investor partners' share of revenues and costs of a partnership among them in the same proportion as each investor partner's capital contribution bears to the aggregate of the capital contributions of all investor partners in the partnership.

To avoid the requirement of restoring a deficit capital account balance, there will be no allocations of losses to an investor partner to the extent those allocations would create or increase a deficit in his or her capital account (adjusted for liabilities, as provided in the limited partnership agreement).

Cash Distribution Policy

We plan to make distributions of partnership cash on a monthly basis, but will make distributions no less often than quarterly, if funds are available for distribution.

We will make cash distributions of 75% to the investor partners and25% to the Managing General Partner throughout the term of the partnership; cash distributions may increase for investor partners and decrease for the Managing General Partner in view of the revised sharing arrangement policy and may decrease for investor partners and increase for the Managing General Partner if the Managing General Partner invests capital above its minimum capital contribution to cover additional tangible well and lease costs.

We cannot presently predict amounts of cash distributions, if any, from the program.

We intend to distribute substantially all of each partnership's available cash flow on a monthly basis to its respective partners; we will make cash distributions not less frequently than quarterly. However, we expressly condition any distribution upon our having sufficient cash available for distribution. In this regard, we will review the accounts of each partnership at least quarterly for the purpose of determining the sufficiency of distributable cash available for distribution. Amounts will be paid to partners only *after* payment of fees and expenses to the Managing General Partner and its affiliates and ***only*** if there is sufficient cash available. The ability of the partnerships to make or sustain cash distributions will depend upon numerous factors. We can give no assurance that any level of cash distributions to the investor partners of a particular partnership will be attained, that cash distributions will equal or approximate cash distributions made to investors in prior drilling programs sponsored by us, or that any level of cash distributions can be maintained. See "Prior Activities" for a tabular presentation of how our previous drilling programs have performed. See also "Risk Factors," in general, and "Special Risks of the Partnership – Drilling natural gas and oil wells is speculative, may be unprofitable, and may result in the total loss of your investment," above, for information regarding the various risks involved if you choose to invest in the partnership.

In general, the volume of production from producing properties declines with the passage of time. We are hopeful that our anticipated recompletions to the partnership's Codell formation wells that we drill in the Wattenberg Field in Colorado will produce additional natural gas. We cannot guarantee that any of our recompletion services will prove economically successful, will generate revenues in excess of the costs of recompletion and will result in additional cash distributions to the investor partners. The cash flow generated by each partnership's activities and the amounts available for distribution to a partnership's respective partners will, therefore, decline in the absence of significant increases in the prices that the partnerships receive for their respective oil and gas production, or significant increases in the production of oil and gas from prospects resulting from the successful additional development of these prospects. If the partnership decides to develop its wells further, the funds necessary for that development would come from that partnership's revenues and/or from borrowed funds. As a result, there may be a decrease in the funds available for distribution, and the distributions to the investor partners of that partnership may decrease.

In general, we will divide cash distributions 75% to the investor partners and 25% to us throughout the term of the partnership. However, we will revise partnership sharing arrangements during the ten-year revision period if the average annual rate of return does not equal established goals. See "Revenues – Revision to Sharing Arrangements," above. **Our revised sharing arrangement policy is not, and no investor should consider the policy to be, any form of guarantee or assurance of a rate of return on an investment in the partnership.** Moreover, we will revise the partnership sharing arrangements if we invest capital above our required minimum capital contribution to cover additional tangible drilling and lease costs. See "Costs – Lease Costs, Tangible Well Costs, and Gathering Line Costs," above. Cash will be distributed to the investor partners and us as a return on capital in the same proportion as their interest in the net income of the partnership. However, no investor partner will receive distributions to the extent the distributions would create or increase a deficit in that partner's capital account.

For a fuller discussion of capital accounts and tax allocations, see "Tax Considerations – Partnership Allocations."

Termination

Upon termination and final liquidation of a partnership, we will distribute the assets of the partnership to the partners based upon their capital account balances. If we have a deficit in our capital account, we must restore the deficit; however, no investor partner will be obligated to restore his or her deficit, if any.

Amendment of Partnership Allocation Provisions

The Managing General Partner may amend the limited partnership agreement without investor approval, if necessary for partnership allocations to be recognized for federal tax purposes.

We are authorized to amend the limited partnership agreement, if, in our sole discretion based on advice from our legal counsel or accountants, an amendment to revise the cost and revenue allocations is required for those allocations to be recognized for federal income tax purposes because of either the promulgation of Treasury Regulations or other developments in the tax law. Any new allocation provisions provided by an amendment must be made in a manner that would result in the most favorable aggregate consequences to the investor partners as nearly as possible consistent with the original allocations described in this prospectus. See Section 11.09 of the limited partnership agreement.

COMPENSATION TO THE MANAGING GENERAL PARTNER AND AFFILIATES

The items of compensation to be paid to the Managing General Partner and its affiliates from each partnership are summarized in the table set forth below. Most of these items of compensation depend on the level of investment in a partnership. In this regard, the minimum investment in any partnership to be formed under this prospectus will be $7 million, and the maximum investment in a partnership will be $70 million. These items are discussed in more detail following the table. See "Conflicts of Interest" for a discussion of the various conflicts of interest involved in the program.

Recipient	Form of Compensation	Amount
Affiliate	Brokerage sales commissions; reimbursement of due diligence, marketing support expenses; and wholesaling fees	10½% of subscriptions – $735,000 ranging to $7,350,000
Managing General Partner	Management fee	1½% of subscriptions -- $105,000 ranging to $1,050,000 (nonrecurring fee)
Managing General Partner	Managing General Partner's drilling compensation	15% of total well costs for operated wells or 5% for non-operated wells
Managing General Partner	Purchased partnership interest	25% working interest
Managing General Partner	Direct costs	Cost
Managing General Partner	Sale of leases to Partnerships	The lower of cost or fair market value
Managing General Partner	Contract drilling rates	Cost
Managing General Partner and Affiliates	Payment for equipment and supplies	Cost
Managing General Partner	Operator's per-well charges and services	Competitive prices
Managing General Partner	Gas marketing charges	Competitive rates

For a tabular presentation of payments to us made by previous partnerships sponsored by us, see "Conflicts of Interest – Certain Transactions," below. The categories of compensation set forth above are comparable to the corresponding categories of compensation for other partnerships sponsored by us disclosed in the "Certain Transactions" table below, except with respect to the management fee which was not a feature of the 1993 partnerships sponsored by us.

Following closing of a partnership and upon funding of that partnership, we will contribute to the partnership an amount in cash equal to 24.4% of the subscriptions of that partnership's investors. In exchange for our investment, we will receive a 25% interest in the partnership. Our interest in the partnership may vary in view of the revised sharing arrangement policy (see "Participation in Costs and Revenues – Profits and Losses; Cash Distributions – Revision to Sharing Arrangements" for a discussion of our allocations policy) and if we invest additional capital to fund that partnership's tangible drilling and lease costs (see "Participation in Costs and Revenues – Costs – Lease Costs, Tangible Well Costs, and Gathering Line Costs").

Compensation Associated with Partnership Sales and Formation

PDC Securities Incorporated, our affiliate and the dealer-manager of the program, in that capacity will receive as sales commissions, for reimbursement of due diligence and marketing support expenses and wholesaling fees of $7,350,000 for sale of the maximum partnership subscriptions of $70,000,000 (3,500 units), ranging to $735,000 for sale of the minimum partnership subscriptions of $7,000,000 (350 units). If all of the 20,000 units registered in the Program's 12 partnerships are sold for total subscriptions of $400,000,000, the total of these fees will be $42,000,000. PDC Securities will, as dealer manager, reimburse due diligence expenses and reallow sales commissions and marketing support expenses in whole or in part to NASD licensed broker-dealers for sale of the units. PDC Securities will retain 2% of subscriptions for wholesaling fees and expenses, meeting costs and other selling expenses, equal to

$140,000 for the sale of the minimum number of 350 units ranging to $1,400,000 for the sale of the maximum 3,500 partnership units in one partnership, and $8,000,000 for the sale of the entire 20,000 units that the program registered. See "Plan of Distribution."

When we complete the offering of each partnership and fund that partnership, we will receive a one-time management fee equal to 1½% of total contributions of the investor partners to the partnership, an amount equal to $105,000 for sale of the minimum number of 350 units in a partnership ranging to $1,050,000 for the sale of the maximum number of 3,500 units in a partnership.

The partnership will reimburse the Managing General Partner for any direct costs incurred on behalf of the partnership at cost.

Compensation Associated with Drilling and Completion Operations

Managing General Partner and Operator Compensation. The Managing General Partner anticipates that it will serve as operator for most, if not all of the partnership's wells. If the Managing General Partner serves as operator of a partnership's well, it will receive drilling compensation equal to 15% of the total well costs paid from the funds of the investor partners for its services as Managing General Partner and operator and for contributing its leases at cost. If the Managing General Partner does not serve as operator of a well, it will receive drilling compensation equal to 5% of the total well costs for its services as Managing General Partner. In the case of wells not operated by the Managing General Partner, the Managing General Partner's geologists and engineers will evaluate any prospects and determine that they meet the criteria of the partnership, and employees of the Managing General Partner will monitor the drilling operations and costs of the wells and the performance of the operator.

Natural Gas and Oil Revenues. Subject to the Managing General Partner's subordination obligation, the investors and the Managing General Partner will share in each partnership's revenues in the same percentages as their respective contributions to the cost of the wells for that partnership. The Managing General Partner's drilling compensation described in the preceding paragraph will not be included in well costs when determining the sharing arrangement. As noted above, the Managing General Partner's revenue share from each partnership is subject to revision as described in "Participation in Costs and Revenues – Profits and Losses; Cash Distributions – Revision to Sharing Arrangements," above.

For example, if the Managing General Partner contributes the minimum of 25% of the partnership's total well costs, excluding its drilling compensation, and the investors contribute 75% of the partnership's total well costs, then the Managing General Partner will receive 25% of the partnership revenues and the investors will receive 75% of the partnership revenues. On the other hand, if the Managing General Partner contributes 30% of the total partnership well costs, excluding its drilling costs, and the investors contribute 70% of the total partnership well costs, then the Managing General Partner will receive 30% of the partnership revenues and the investors will receive 70% of partnership revenues. The Managing General Partner is required to contribute all of the costs of the wells that are not classified as intangible drilling costs, but not less than 25% of the total well costs.

Lease costs Under the partnership agreement, the Managing General Partner will sell to each partnership undeveloped prospects. The sales price will be equal to:

- the cost of the prospects; or
- the fair market value of the prospects if the Managing General Partner has reason to believe that cost is materially more than the fair market value.

The cost of the leases will include a portion of the Managing General Partner's reasonable, necessary, and actual expenses for services allocated to a partnership's leases by it using industry guidelines.

The Managing General Partner's lease cost for the partnerships funded in 2002, 2003, and 2004 have averaged $21,948 per net well or 2.6% of partners' subscriptions. See the "Certain Transactions" table on page ___ for a listing of lease costs per partnership.

- Some of the leases contributed to the above-referenced partnerships were acquired by the Managing General Partner several years ago when the sales price environment was lower; therefore, the cost of those leases were also lower. The Managing General Partner has seen a significant increase in acreage cost and would expect higher lease costs in the future if this current energy price environment continues. Therefore, the costs charged to the partnership may be significantly higher for future partnerships than the partnerships have experienced in the past.

Drilling a partnership's wells may also provide the Managing General Partner with offset prospects to be drilled by allowing it to determine at the partnership's expense the value of adjacent acreage in which the partnership would not have any interest.

Drilling Costs. Each partnership will enter into the drilling and operating agreement with the Managing General Partner to drill and complete each partnership's wells at cost. If the Managing General Partner provides services in the drilling and completion of the wells, it will charge those services at its cost, not to exceed competitive rates charged in its area of operation. The Managing General Partner will determine competitive rate based on information it has concerning rates of third-party service providers in the areas where partnership wells are drilled. If these rates subsequently exceed competitive rates available from other qualified non-affiliated persons in the area engaged in the business of rendering or providing comparable services or equipment, then the rate will be adjusted to the competitive rate.

The Managing General Partner expects to subcontract third-party services for drilling and completion activities of each partnership's wells. These services will be billed to the partnerships at actual third party costs. The Managing General Partner may not benefit by interpositioning itself between the partnership and the actual provider of drilling contractor services, and may not profit by drilling in contravention of its fiduciary obligations to the partnership.

Cost, when used with respect to services, generally means the reasonable, necessary, and actual expense incurred in providing the services, determined in accordance with generally accepted accounting principles. The cost of the well also includes all ordinary costs of drilling, testing and completing the well. Following are some of the costs of a natural gas well, which will be the classification of the majority of the wells:

- location and surface damages;
- location construction;
- drilling;
- logging;
- completion including multiple completions, which means, in general, treating separately all potentially productive geological formations in an attempt to enhance the gas production from the well;
- well casing pipe and surface production equipment;
- installing gathering lines for natural gas; and
- fixed rate overhead in accordance with industry accounting standards (COPAS).

The well costs charged to the partnership will be proportionately reduced to the extent a partnership acquires less than 100% of the working interest in a prospect. The amount of compensation that the Managing General Partner could earn as a result of these arrangements depends on the degree to which it provides services for the wells, and the number and type of wells that are drilled. The current monthly fixed drilling overhead rate for Wattenberg Field and Grand Valley Field wells is $7,500 per month for wells between 5,000 and 10,000 feet deep. Charges begin on the day when drilling or completion equipment moves on location, and end when the drilling rig or completion equipment is released, whichever occurs later. No charge is made during suspension of operations for 15 or more consecutive calendar days. A typical Wattenberg Field well will require one to two months to drill and complete, and a typical Grand Valley well will require two to three months to drill and complete. For typical Wattenberg Field wells, the fixed rate overhead charges are expected to amount to approximately $7,500 to $15,000, and in Grand Valley Field they are expected to be $15,000 to $22,500. If the Managing General Partner supplies other goods and services to the partnership, it will be required to supply them at cost, and they will be included in the total well costs for determining the Managing General Partner’s and the investors’ contributions, the division of oil and gas revenues, and calculation of the Managing General Partners drilling compensation.

Because the Managing General Partner is billing for the wells and its services at cost, its profit will be the 15% of total well costs (5% for wells where it does not serve as operator) it charges the partnership as Managing General Partner’s drilling compensation, less its costs for the partnership’s administrative costs. The Managing General Partner will bear all non-COPAS administrative costs (as defined by the Council of Petroleum Accountants Societies) of the partnerships during the drilling and completion phase of operations. Those costs will not count toward its contribution to the cost of the wells. The Managing General Partner estimates that administrative costs (primarily legal, blue sky compliance, printing and mailing costs) will be approximately 1% of the partnership subscriptions. The Managing General Partner estimates that its drilling compensation on drilling for the minimum amount of capital raised ($7 million in partnership subscriptions) will be $1,026,667 and that it will bear administrative costs of $70,000, ranging to drilling compensation of $10,266,667 for the maximum amount of capital raised in a partnership ($70 million) with administrative costs of $700,000.

Per Well Charges

Under the drilling and operating agreement, the Managing General Partner, as operator of the wells, will receive the following from each partnership when the wells begin producing:

- reimbursement at actual cost for all direct expenses incurred on behalf of the partnership, and
- well operating charges for operating and maintaining the wells during producing operations at a competitive rate.

During the production phase of operations, the operator will receive for each producing well a monthly fee based upon competitive industry rates for operations and field supervision and $75 for partnership accounting, engineering, management, and general and administrative expenses. The operator will bill non-routine operations to the partnership at its costs. See "Proposed Activities – Drilling and Completion Phase – Drilling and Operating Agreement" for a discussion of our drilling policy and the costs involved in drilling and operating partnership wells. In this regard, see the table “Initial Per Well Operating Charges” set forth below under that caption. The Managing General Partner may not benefit by interpositioning itself between the partnership and the actual provider of operator services. In no event will any consideration received for operator services be duplicative of any consideration or reimbursement received under the partnership agreement.

The well operating charges cover all normal and regularly recurring operating expenses for the production, delivery, and sale of natural gas and oil, such as:

- well tending, routine maintenance, and adjustment;
- reading meters, recording production, pumping, maintaining appropriate books and records; and
- preparing reports to the partnership and government agencies.

The well supervision fees do not include costs and expenses related to:

- the purchase of equipment, materials, or third-party services;
- the cost of compression and third-party gathering services, or gathering costs;
- brine disposal; and
- rebuilding of access roads.

These costs will be charged at the invoice cost of the materials purchased or the third-party services performed.

Gathering Fees

Under the partnership agreement, the Managing General Partner will be responsible for gathering and transporting the natural gas produced by the partnerships to interstate pipeline systems, local distribution companies, and/or end-users in the area from the point the gas from the well is commingled with gas from other wells. In such a case the Managing General Partner anticipates that it will use gathering systems already owned by us or that we will construct the necessary facilities if no such line exists. In such a case, the partnership will pay a gathering fee directly to the Managing General Partner at competitive rates. If a third-party gathering system is used, the partnership will pay a gathering fee to the third-party gathering the natural gas.

Gas Marketing and Other Fees

We and our affiliates may enter into other transactions with the partnerships for services, supplies and equipment during the production phase of the partnerships, and will be entitled to compensation at competitive prices and terms as determined by reference to charges of unaffiliated companies providing similar services, supplies and equipment. We intend to market some of the gas produced through our subsidiary Riley Natural Gas. Charges for those services will be at competitive rates.

PROPOSED ACTIVITIES

Introduction

- The primary purpose of the partnerships will be drilling, completing, and producing natural gas and oil from development wells.

- We may conduct limited exploratory activities.

- Partnerships will acquire up to 100% of the working interest of each prospect, subject to royalty interests.

- Each partnership will be a separate business entity.

- Investors in one partnership will have no interest in any of the other partnerships.

The partnerships will drill, complete, own and operate natural gas and oil wells. We anticipate that the partnership will drill most, if not all, of its wells in Colorado. However, partnership operations may include wells in North Dakota, Alabama, Michigan, West Virginia, Pennsylvania, Utah, and Wyoming. We may also conduct partnership operations in other formations not described in the prospectus, in the previously listed states, or in Montana, New York, South Dakota, Kentucky, Tennessee, Indiana, Kansas, Nebraska, Ohio, Texas and/or Oklahoma as we may deem advisable. We intend to apply at least 90% of each partnership's capital contributions available for participation in drilling and completion activities to comparatively lower risk development wells but may apply some of the remaining 10% to comparatively higher risk exploratory wells. We will spread the risks to a limited extent by having each partnership participate in drilling operations on a number of different prospects. The cost of drilling wells in different geographic locations will vary greatly. If we drill more expensive wells, the partnership will be able to drill fewer wells. As a result, the partnership will be less able to diversify its investment, and the risk associated with drilling will increase. The number of wells drilled by a partnership is determined by the amount of funds raised for that partnership and the specific prospects drilled by that partnership, and cannot be determined in advance of funding of a partnership.

The program provides you with an opportunity to invest in the drilling, completion, and production of natural gas and oil wells. Please see page 1 of this prospectus for a description of the objectives of the investment in the program.

You should be aware that distributions will decrease over time due to the declining rate of production from wells. Changes in gas and oil prices will decrease or increase cash distributions. Distributions will be partially sheltered by the percentage depletion allowance. See "Risk Factors – Special Risks of the Partnerships," " – Risks Pertaining to Oil and Gas Investments," and " – Tax Status and Tax Risks," "Prior Activities," and "Tax Considerations – Summary of Conclusions," " – Intangible Drilling and Development Costs," " – Depletion Deduction," " – Partnership Distributions," and " – Partnership Allocations" for a discussion of the various risks involved if you invest in the program.

The attainment of the partnership's business objectives will depend upon many factors, including our ability to select productive prospects, the drilling and completion of wells in an economical manner, the successful management of the prospects, the level of natural gas and oil prices in the future, the availability of pipelines sufficient to transport the natural gas and oil that we produce, the degree of governmental regulation over the production and sale of natural gas and oil, the future economic conditions in the United States (and the world), and changes in the Internal Revenue Code. Accordingly, we can give no assurance that the partnership will achieve its business objectives. Moreover, because each partnership will constitute a separate and distinct business and economic entity from each other Partnership, the degree to which the business objectives are achieved will vary among the partnerships.

Various of the activities and policies of the partnership discussed throughout this section and elsewhere in the prospectus are defined in and governed by the limited partnership agreement, including that at least 90% of the net offering proceeds will be used to drill development wells; the requirements relating to the acquisition of prospects and the payment of royalties; the amount of our capital contribution to the partnership; the guidelines with respect to well pricing and the cost of services furnished by us; the states where the partnership's wells will be drilled; assessments and borrowing policies; voting rights of investor partners; the term of the partnership; and our compensation. Other policies and restrictions upon the activities of the partnership and us are not set forth in the limited partnership agreement, but instead reflect our current intention and thus are subject to change at our discretion. For these later activities, we, in making a change, will utilize our reasonable business judgment as manager of the partnership and will exercise our judgment consistent with our obligations as a fiduciary to the investor partners.

Upon the successful completion of the offering, the partnership will effect the following transactions, each of which is more fully described below:

- We will assign to the partnership up to 100% of the working interest in the prospects; and

- The partnership will enter into a drilling and operating agreement with us or with unaffiliated persons as operator, providing

    - for the drilling and completion of partnership wells and

    - for the subsequent supervision of field operations with respect to each producing well.

<u>Drilling Policy</u>

Most wells will be offsets to producing wells.

The partnerships expect to conduct recompletion operations regarding its Codell formation wells that the partnerships drill in the Wattenberg Field in Colorado.

Each partnership will invest in a number of prospects, either by itself or in conjunction with other parties, consistent with the objective of maintaining a meaningful interest in the wells to be drilled. The partnerships will not acquire any interest in currently or formerly producing gas and oil wells. Most wells to be drilled by the partnerships will be adjacent to producing wells and drilled to the same formation(s) as the producing wells. Therefore, it is unlikely that a well on a prospect will have the effect of proving up any additional acreage outside of the prospect. For this reason, the partnerships are expected to acquire spacing units on each prospect determined by state rules and regulations in conjunction with local practice. The spacing unit for Colorado wells will encompass approximately 32 acres for wells drilled in the Wattenberg Field and approximately 10 – 20 acres for wells drilled in the Grand Valley Field.

To the extent the partnership participates in Codell formation wells in Wattenberg Field, we expect to be able to "recomplete" the Codell formation after the wells have been in production for 5 years or more. A recompletion consists of a second fracture treatment of the formation similar to the fracture treatment used when the well is first completed. The cost of a recompletion is about one third of the cost of a new well (currently about $125,000 for the recompletion). We will charge only our costs for recompletions without any markup or profit, and PDC will pay its share of costs based on the division of revenues from oil and gas sales from the partnership. PDC and other producers have found that the recompletions typically increase the production rate and recoverable reserves of the wells significantly. PDC has recompleted over 180 Codell wells to date. Substantially all of those wells have experienced significant production increases.

Currently we plan to recomplete most Codell wells that the partnership drills after approximately six years of production, although the exact timing may be delayed if we are experiencing a period of low prices or for operational reasons. The partnerships will borrow the funds necessary to pay for the recompletions, and payment for those loans will be made from the partnership production proceeds. Any such loans will be non-recourse to the investor partners in the partnership.

Although our experience to date with Codell recompletions has been very good generally, not all recompletions have been successful. If the partnership participates in unsuccessful recompletions, it may have additional costs without having sufficient incremental revenue to pay those costs. This would reduce the funds available for distribution to the investors and PDC.

Acquisition of Undeveloped Prospects

The Managing General Partner will select undeveloped prospects.

Selection of prospects for a partnership will occur after that partnership has been funded.

At least 90% of prospects will be development wells.

The partnerships will acquire prospects at the lesser of the Managing General Partner's cost or fair market value.

The average of the royalty and overriding royalty burden for all of the prospects for the partnership will not exceed 25%.

The Managing General Partner will not retain overriding royalty interests.

We will select undeveloped prospects sufficient to drill the partnerships' wells. We have not pre-selected any prospects. Most prospects to be selected for the partnerships are expected to be single well proved undeveloped prospects. We define a prospect generally as a contiguous oil and gas leasehold estate, or lesser interest, upon which drilling operations may be conducted for a single development well. See "Glossary of Terms" in general and more particularly "Glossary of Terms – Proved Undeveloped Reserves" and "– Proved Oil and Gas Reserves" below, for definitions of the various terms used in this section of the prospectus.

Depending on its attributes, a prospect may be characterized as an "exploratory" or "development" site. Generally speaking, exploratory drilling involves the conduct of drilling operations in search of a new and yet undiscovered pool of oil and gas (or, alternatively, drilling within a discovered pool with the hope of greatly extending the limits of that pool), whereas development drilling involves drilling to a known producing formation in a previously discovered field.

The partnership intends to conduct the majority of its development drilling operations in Colorado to develop Cretaceous Sandstones. We reserve the right to conduct partnership operations in New York, Ohio, Montana, North Dakota, Alabama, South Dakota, Tennessee, Kentucky, Indiana, Kansas, Nebraska, Pennsylvania, West Virginia, Utah, Wyoming, Texas and/or Oklahoma and/or to other formations as we may, in our sole and absolute discretion, deem advisable, provided that the locations and/or formations are, in our opinion, of comparable quality and character to those described in this prospectus.

Wells in the intended area of operations are usually given a fracture treatment in which fluids are pumped into the potential zone in an attempt to create additional fractures and widen present fractures. We anticipate that gas will be produced from all the subject wells, and that most Wattenberg Field wells in Colorado will also produce significant quantities of oil. There could also be some oil and brine production from wells in any area. Many zones which contain oil and gas will not produce or will only produce at low rates unless they are treated to allow the oil and gas to reach the well more easily. One method to accomplish this is by using a fracture treatment. The most commonly used fracture treatment method uses a mixture of sand and treated water pumped at high pressure and flowrates into the well and out through holes in the pipe at the productive zone. This creates cracks in the pay zone which reach out into the zone to allow oil or gas to flow into the well more easily. When the pumping of the fracturing fluid is stopped, the sand props the fractures open so they don't reseal under the pressure from the earth above.

The partnerships will acquire prospects under arrangements in which the partnership will acquire up to 100% of the working interest, subject to landowners' royalty interests and other royalty interests payable to unaffiliated third parties in varying amounts, provided that the average of the royalty interests for all prospects of a particular partnership will not exceed 25%. In our discretion, the partnership may acquire less than 100% of the working interest in a prospect provided that costs are reduced proportionately. The limited partnership agreement forbids us from acquiring or retaining any overriding royalty interest in the partnership's interest in the prospects. The partnerships will generally acquire less than 100% of the working interest in each prospect in which they participate. In order to comply with the conditions for the treatment of additional general partners' interests in the partnership as not passive activities (and not subjecting the additional general partners to limitation on the deduction of partnership losses attributable to the additional general partners to income from passive activities), we have represented that the partnerships will acquire and hold only operating mineral interests and that none of the partnership's revenues will be from non-working interests. We, for our sole benefit, may sell or otherwise dispose of prospect interests not acquired by the partnerships or may retain a working interest in the prospects and participate in the drilling and development of the prospect. In such case the partnership costs would be proportionally reduced, based on their interest in the property, and we (or the parties) would pay for the costs of the non-partnership interests.

In acquiring interests in leases, the partnerships may pay consideration and make contractual commitments and agreements as we deem fair, reasonable and appropriate. While we expect to assign to the partnerships a substantial portion of the leases to be developed by the partnerships, the partnerships may also purchase leases directly from unaffiliated persons. We will transfer at our cost all leases which are transferred to the partnerships, unless we have reason to believe that cost is materially more than the fair market value of the property in which case the price will not exceed the fair market value of the property. We will obtain an appraisal from a qualified independent expert with respect to sales of our properties to the partnerships.

The actual number, identity and percentage of working interests or other interests in prospects to be acquired by the partnerships will depend upon, among other things, the total amount of capital contributions to a partnership, the latest geological and geophysical data, potential title or spacing problems, availability and price of drilling services, tubular goods and services, approvals by federal and state departments or agencies, agreements with other working interest owners in the prospects, farm-ins, and continuing review of other prospects that may be available.

Title to Properties

The partnership will hold record title to leases, spacing units or portions of leases/units in its name.

We will assign the partnership interest in the lease to the partnership. Leases acquired by each partnership may initially and temporarily be held in our name, as nominee, to facilitate joint-owner operations and the acquisition of properties. The existence of the unrecorded assignments from the record owner will indicate that the leases are being held for the benefit of each particular partnership and that the leases are not subject to debts, obligations or liabilities of the record owner; however, unrecorded assignments may not fully protect the partnerships from the claims of our creditors.

You must rely on us to use our best judgment to obtain appropriate title to leases. Provisions of the limited partnership agreement relieve us from any mistakes of judgment with respect to the waiver of title defects. We will take those steps as we deem necessary to assure that title to leases is acceptable for purposes of the partnerships. We are free, however, to use our own judgment in waiving title requirements and will not be liable for any failure of title to leases transferred to the partnerships. Further, we will not warrant the validity or merchantability of titles to any leases to be acquired by the partnerships. We are accountable to the partnerships as a fiduciary and consequently must exercise our good faith and integrity in handling partnership affairs. Moreover, we must act at all times in the best interests of the partnership and the investor partners.

PDC Prospects

We anticipate that ourgeologists (see "Management – Petroleum Development Corporation" for their identities and a summary of their experience) will evaluate all prospects, utilizing log and geological data from our historic operations, production records from our and others' wells, and other information as may be available and useful. Most oil and gas is found in areas where the rocks include sandstones, shales, salt, gypsum and limestone. They are frequently deposited in distinct layers like the ones you sometimes see where highways cut through mountains. By studying the rocks penetrated by wells in an area, it is possible to develop "maps" of these different layers in the area. These maps help geologists predict the best places to drill new wells. As a result, nearly all wells drilled by the partnership will be direct offsets to existing producing wells. Where multiple zone potential exists, the geologists attempt to optimize well locations to create wells with two or more productive horizons.

As of May 31, 2005, we had acreage available as listed in the following table within the prospect area.

State	Acreage
North Dakota	14,704
Wyoming	22,395
Kansas	21,100
Michigan	3,000
Colorado	103,480
Total	164,679

In addition, we expect to acquire additional acreage on an ongoing basis throughout 2005 and beyond for the program and future partnerships.

We will not decide on the specific wells to be drilled in any partnership until the offering of units in that partnership has terminated. This means that, prior to your investment in the partnership, you will not be able to evaluate the specific prospects that will be drilled by your partnership. However, by waiting as long as possible before selecting the specific prospects to be drilled by the partnership, we may have information available which helps us select better prospects for the partnership, and we may be able to include prospects which were not available when this prospectus was written or even before the partnership was closed. This section includes a general description of the characteristics we look for in prospects to be included in the program as well as more detailed information on several areas where we anticipate partnership wells may be drilled. We will provide supplemental information if and when we add additional prospect areas.

In selecting areas where we plan to drill partnership wells, we look for areas with most or all of the following general characteristics:

Natural gas is expected to be the primary product for most wells, but some prospects may be drilled primarily for their oil production potential or for combined oil and gas production

Onshore wells with depths of 15,000 feet or less

Expected average producing lives of 20 years or more

Existing pipeline systems which allow quick connection for sales

Adequate market capacity for increased gas production

Low dry hole risk

Most of the wells to be drilled by the partnerships will be targeted at natural gas producing intervals. These intervals may also contain oil and/or water which are produced in conjunction with the natural gas. Some natural gas also contains hydrocarbons like propane and butane which may be separated from the natural gas and sold. Water that is produced must be disposed of by an environmentally approved method, which adds to the cost of operating the wells.

Over the past 34 years, we have drilled more than 2,400 wells at depths ranging from 1,000 feet to just over 14,000 feet. When we select new prospect areas, we look for places where the drilling conditions are similar to areas where we have had drilling experience and where the well depths do not exceed approximately 15,000 feet. Because we have had no offshore experience, we do not plan to include any offshore prospects in the program.

Since we started organizing partnerships in 1984, we have completed more than 94 percent of the wells we have drilled for our partnerships to produce natural gas and/or oil. In Colorado, we have completed 98% of the wells as productive wells. Our completion record reflects our selection of prospect areas where the probability of drilling dry holes is relatively low because producing intervals exist throughout a large area and because each well may access several intervals which are capable of producing natural gas or oil. Nevertheless, the fact that prospect areas where we are considering to drill our wells have had a history of successful drilling and production does not guarantee that the wells will be commercially successful if the wells do not produce sufficient quantities of natural gas and oil or if the prices for natural gas and oil are at low levels.

All of the areas we are currently developing fit this general description and we plan to look for similar characteristics in prospect areas we might add in the future. We also look for areas where the characteristics of the producing formations lead to relatively long producing lives, generally of 20 years or more. Production from wells typically commences at a maximum rate that diminishes over the life of the well. This means that the income stream from the wells will also tend to decline over time, depending upon other factors including the sales price for the production and operating expenses.

As we evaluate the geology of a prospect area, we also determine whether there is an adequate market for natural gas and oil which may be produced by the wells. For natural gas, this includes the existence of pipelines to move the gas from the wells to natural gas markets. We investigate the proximity of existing pipelines to planned drilling, the cost of moving gas to market, and prices being paid for gas in the markets which are available. Similarly, there must be both a market and suitable transportation for oil production.

Current Prospect Areas

Colorado. Wattenberg Field, located north and east of Denver, Colorado, is in the Denver-Julesburg (DJ) basin. The field, discovered in 1970, has produced over 600 billion cubic feet of natural gas and 2.2 million barrels of oil. The typical well production profile has an initial high production rate and relatively rapid decline, followed by years of relatively shallow decline. Natural gas is the primary hydrocarbon; however, many wells will also produce oil. The purchase price for the gas may include revenue from the recovery of propane and butane in the gas stream, as well as a premium for the high-energy content of the gas. Wells in the area may include as many as four productive formations. From shallowest to deepest, these are the Sussex, the Niobrara, the Codell and the J Sand. The primary producing sand in most wells will be the Codell sand which produces a combination of natural gas and oil.

The Piceance Basin, located near the western border of Colorado, is a second Colorado prospect area. We expect our Piceance Basin wells to produce natural gas along with very small quantities of oil and water. The producing interval consists of a total of 150' to 300' of productive sandstone divided in 10 to 15 different zones. The production zones are separated by layers of nonproductive shale resulting in a total interval of 2000' to 4000' penetrated by the well. The gas reserves and production are divided into these numerous smaller zones.

The Sand Wash Basin, located in northwestern Colorado, is a third potential prospect area. Successful wells drilled in this area are expected to produce primarily natural gas with small associated amounts of oil and water. Several upper Cretaceous and Tertiary aged sandstone reservoirs are prospective for commercial hydrocarbon production in the prospect area. The deepest potential targets are part of the Mesaverde including the Lewis, Fox Hills and Lance formations. In addition, shallower Tertiary aged Fort Union and Wasatch Sands may be secondary targets. Well depths may range approximately from 8,000 to 12,000 feet or more depending upon structural position within the basin. It is anticipated that several stacked sandstone sequences may be productive in a single well. Wells may range from development, to field extension, to exploratory and will likely be drilled offsetting previously drilled wells where electric well log information is available.

Wyoming. The Red Desert Basin, located in southwestern Wyoming, is a fourth potential prospect area. Successful wells drilled in this area are expected to produce primarily natural gas with small associated amounts of oil and water. Several upper Cretaceous and Tertiary aged sandstone reservoirs are prospective for commercial hydrocarbon production in the prospect area. The deepest potential targets are part of the Mesaverde including the Lewis, Fox Hills and Lance formations. In addition, shallower Tertiary aged Fort Union and Wasatch Sands may be secondary targets. Well depths may range approximately from 8,000 to 12,000 feet or more depending upon structural position within the basin. It is anticipated that several stacked sandstone sequences may be productive in a single well. Wells may range from development, field extension to exploratory and well likely be drilled offsetting previously drilled wells where electric well log information is available.

Summary of Prospect Areas

The following table summarizes some of the key characteristics of our current prospect areas:

Prospect	Productive Formation	Depth Range	Type of Reservoir Rock	Thickness of Producing Interval	Anticipated Production
Wattenberg Field, Colorado	Sussex	3,750' - 5,250'	Sandstone	10' - 60'	Natural gas
	Niobrara	6,500' - 7,500'	Limestone	20' - 80'	Natural gas
	Codell	6,750' - 7,750'	Sandstone	10' - 30'	Natural gas, oil
	J Sandstone	7,500' - 8,400'	Sandstone	2' - 90'	Natural gas
Piceance Basin, Colorado	Williams Fork	6,000' - 10,000'	Sandstone and Coal	150' - 300' total pay in a 2,000' - 4,000' interval	Natural gas
Sand Wash Basin, Colorado	Lance	8,000' - 10,000'	Sandstone	5' - 200'	Natural gas
	Lewis/Fox Hills	9,000' - 11,000'	Sandstone	50' - 200'	Natural gas
	Lower Mesaverde	10,000' - 13,000'	Sandstone	25' - 150'	Natural gas
Red Desert	Lance	8,000' –	Sandstone	50' - 200'	Natural gas

Prospect	Productive Formation	Depth Range	Type of Reservoir Rock	Thickness of Producing Interval	Anticipated Production
Basin,Wyoming		10,000'			
	Lewis/ FoxHills	9,000' – 11,000'	Sandstone	50' - 200'	Natural gas
	Lower Mesaverde	10,000' – 13,000'	Sandstone	25' - 150'	Natural gas

<u>Drilling and Completion Phase</u>

Partnership wells in Colorado may be exploratory or developmental with depths expected to range from approximately 6,500 to 13,000 feet in depth.

At least 90% of partnership wells will be developmental.

The partnership is expected to conduct recompletion operations on its Codell formation wells in the Wattenberg Field.

The Managing General Partner will drill partnership wells near pipelines, gathering systems, or end users.

The partnership will sell production on a competitive basis at the best available price.

<u>General</u>: The table above shows the anticipated depths and target formations for planned areas of operations.

We may drill some shallower or deeper development prospects in these areas. If we drill wells in other areas, it is likely that well depths will differ. After drilling, the operator will complete each well deemed by the operator to be capable of production of oil or gas in commercial quantities. We intend to apply to development wells at least 90% of each partnership's capital contributions available for participation in drilling and completion activities. We may drill exploratory wells to depths exceeding the proposed developmental well depths indicated above. If the funds allocated for exploratory wells are not used to drill exploratory wells, we will utilize these funds together with unexpended completion funds to drill additional development wells. We anticipate that the partnership wells that we drill in the Wattenberg Field in Colorado will need recompletion services following initial drilling so that these wells might be their most productive. We anticipate that we will commence recompletion activities approximately five years following our completion of initial drilling of the partnership’s wells. Recompletion services, which currently cost approximately $125,000 per well, will require significant additional funding by the partnership. The limited partnership agreement permits the partnership to borrow funds for its activities. The partnership may borrow funds from the Managing General Partner or affiliates of the Managing General Partner or from unaffiliated persons.

We have acted as operator on all of the wells drilled by our previous drilling partnerships. We may substitute another operator or operators to perform the duties of the operator, on terms and conditions substantially the same as those discussed in this prospectus. Additionally, with respect to those prospects as to which the partnership owns less than a 50% working interest, it is possible that the majority owner of the prospects will select the operator for the wells drilled on the prospects and that the operator may not be us. If another company acts as operator, we will monitor the performance and activities of the operator, participate as the partnership's representative in decision-making with regard to the joint venture activities, and otherwise represent the partnership with regard to the activities of the joint venture. Where someone other than us serves as operator, the cost of drilling to the partnership will be the actual cost of third-party drilling, plus our costs of supervision, engineering, geology, and other services provided,monthly overhead specified in "Compensation to the Managing General Partner and Affiliates," above and the Managing General Partner’s drilling compensation of 5% of well costs.

We will represent each partnership in all operations matters, including the drilling, testing, completion and equipping of wells and the sale of each partnership's oil and gas production from wells of which we are the operator. We expect to be the operator of most if not all of the wells in which the partnerships own an interest.

We will, in some cases, provide equipment and supplies, and will perform salt water disposal services and other services for the partnerships. We may sell equipment to the partnerships as needed in the drilling or completion of partnership wells. All equipment and services will be sold at the lesser of cost or competitive prices in the area of operations.

Gas Pipeline and Transmission: We will drill the partnership's wells in the vicinity of transmission pipelines, gathering systems, and/or end users. We believe that there are sufficient transmission pipelines, gathering systems, and end users for the partnership's production, subject to some seasonal curtailment. The cost, timing and availability of gathering pipelines connections and service varies from area to area, well to well, and over time. In selecting prospects for the partnerships, we include in our evaluation the anticipated cost, timing and expected reliability of gathering connections and capacity. Sometimes when a lot of development work is being done in an area, production can temporarily exceed the available markets and pipeline capacity to move gas to more distant markets. This can lead to lower gas prices relative to other areas as the producers compete for the available market by reducing prices. It can also lead to curtailments of production and periods when wells are shut-in due to lack of market. Beginning in 2001 and throughout most of 2002, the Rocky Mountain region, including our Colorado development areas, experienced reduced prices and occasional curtailments as a result of this sort of situation. In May of 2003 a new major pipeline to move gas from the Rocky Mountain region to Nevada and southern California was placed in service. The pipeline moves over 900 million cubic feet of gas per day out of the region according to the owner, Kern River Pipeline Company. This new pipeline has solved the earlier overcapacity problem. However, if producers continue to successfully develop new supplies in the area, a similar situation as experienced during 2001 and 2002 could develop again in the future.

Sale of Production: Each partnership will sell the oil and gas produced from its prospects on a competitive basis at the best available terms and prices. We intend to utilize the services of our subsidiary Riley Natural Gas in marketing the gas produced from partnership wells. We will not make any commitment of future production that does not primarily benefit the partnerships. Generally, purchase contracts for the sale of oil are cancelable on 30 days' notice, whereas purchase contracts for the sale of natural gas may range from spot market sales of short duration to contracts with a term of a number of years and that may require the dedication of the gas from a well for a period ranging up to the life of the well.

Each partnership will sell natural gas discovered by it at negotiated prices based upon a number of factors, including the quality of the gas, well pressure, estimated reserves, prevailing supply conditions and any applicable price regulations promulgated by the Federal Energy Regulatory Commission. The partnership expects to sell oil discovered by it at market prices. See "Competition, Markets and Regulation" for a discussion of these aspects of the drilling business.

Price Hedging

Oil and natural gas spot market prices have been extremely variable in the past, and the variability will probably continue in the future. In order to assure a more predictable cash flow stream from partnership wells, we may use financial hedges, puts, calls, and other hedging instruments to help offset variations in prices. Sometimes these hedges may result in higher cash flow than would otherwise have been received, but at other times it may result in a more predictable but lower distribution. See Footnote 11 to Consolidated Balance Sheets regarding hedging activities.

Drilling and Operating Agreement

On wells where the Managing General Partner is operator, it will have full control over the partnerships' wells.

The operator must commence drilling wells within 180 days after funding of the partnership, but not later than March 31, 2005 for partnerships designated "PDC 2004- Limited Partnership," March 31, 2006 for partnerships designated "PDC 2005- Limited Partnership" and March 31, 2007 for partnerships designated as "PDC 2006- Limited Partnership."

The costs charged for drilling and completion, dry holes, and monthly operations will be competitive with rates charged for similar services and will vary by the location of the wells. Rates for areas which are currently active are shown in the table in this section.

Upon funding of each partnership, the particular partnership will enter into a drilling and operating agreement with us as operator. The drilling and operating agreement (filed as Exhibit 10(a) to the registration statement) provides that the operator will conduct and direct and have full control of all operations on the partnership's prospects. The operator will have no liability as operator to the partnership for losses sustained or liabilities incurred, except as may result from the operator's negligence or misconduct. Under the terms of the drilling and operating agreement, we may subcontract responsibilities as operator for partnership wells. We will retain responsibility for work performed by subcontractors as set forth in this prospectus.

It is possible that we will not be operator on some of the partnership's prospects. Where the duties of operator are subcontracted to an independent third party, the cost of the wells to the partnership will be determined by the actual third party costs, plus our charges for supervision, engineering, geology, and other services, the fixed rate overhead charge for the area where the well is located and our markup. These charges are expected to be comparable to the rates in this prospectus.

The partnership will pay a proportionate share of total lease, development, and operating costs, and will receive a proportionate share of production subject only to royalties and overriding royalties. At our discretion, the partnership may enter into joint ventures which allow a functional allocation of tangible, intangible and lease costs, where each joint venturer is responsible for its own overhead costs, provided the partnership's interest in the revenues and income of the joint venture is proportional to its contribution to the total cost of the venture.

Each partnership will be responsible only for its obligations and will be liable only for its proportionate share of the costs of developing and operating the prospects; and, in the event of the default by another party, we have agreed to indemnify the partnership and its partners for the obligations of that party. If any party fails or is unable to pay its share of expense within 60 days after receiving a statement for these expenses from us, we will pay the unpaid amount in the proportion that the interest of each party bears to the interest of all parties.

The operator is obligated to commence drilling the wells on each prospect within 180 days of the date of the funding of the partnership, but in no case later than March 31, 2005 for partnerships designated "PDC 2004- Limited Partnership," March 31, 2006 for partnerships designated "PDC 2005- Limited Partnership," and March 31, 2007 for partnerships designated "PDC 2006- Limited Partnership." The operator's duties include testing formations during drilling, and completing the wells by installing surface and well equipment, gathering pipelines, heaters, separators, etc., as are necessary and normal in the area in which the prospect is located. We will pay the drilling and completion costs of the operator as incurred, except that we are permitted to make advance payments to the operator where necessary to secure tax benefits of prepaid drilling costs and where there is a substantial business purpose for the advance payment. In order to comply with conditions to secure the tax benefits of prepaid drilling costs, the operator under the terms of the drilling and operating agreement will not refund any portion of amounts paid in the event actual costs are less than amounts paid but will apply any amounts solely for payment of additional drilling services to the partnership. If the operator determines that the well is not likely to produce oil and/or gas in commercial quantities, the operator will plug and abandon the well in accordance with applicable regulations.

Each partnership will bear its proportionate share of the cost of drilling and completing or drilling and abandoning wells, as follows:

1) The cost of the prospect;

2) The intangible well costs; and

3) The costs of tangible well equipment for the partnership wells and of gathering pipelines necessary to connect the well to the nearest appropriate sales point or delivery point.

In addition, the partnership will pay the Managing General Partner's drilling compensation of 15% where we serve as operator, or 5% if we are not operator.

To the extent that a partnership acquires less than 100% of a prospect, its drilling and completion costs of that prospect will proportionately decrease.

The drilling and operating agreement provides that the partnership will pay the operator the prospect cost and the dry hole cost for each planned well prior to the spud date, and the balance of the completed well costs when the well is completed and ready for production, in the case of a completed well. For year-end drilling contracts in which the partnership prepays the partnership's drilling costs, we will propose AFEs for sufficient wells to account for all of the partnership's remaining funds. The contract will be non-refundable, with amounts in excess of the actual amount applied to the wells and with substitution rights. Substitution rights allow us to replace a proposed well with a different property; for example, if a proposed well is delayed or drilling results from another well make the proposed well less attractive.

The operator will provide all necessary labor, vehicles, supervision, management, accounting, and overhead services for normal production operations, and will deduct from partnership revenues a monthly charge based upon competitive industry rates for each producing well for operations and field supervision (well tending fees) and a monthly charge of $75 per well for partnership accounting, engineering, management, and general and administrative expenses. Charges for areas with current operations are shown below.

INITIAL PER WELL OPERATING CHARGES

WELL LOCATION	MONTHLY PARTNERSHIP ADMINISTRATION	MONTHLY WELL TENDING FEE
Wattenberg Field	$75	$325
Piceance Basin	$75	$600
Sand Wash Basin	$75	$600
Red Desert Basin	$75	$600

If the partnership has producing wells in areas different from those above, the operator will charge a monthly partnership administration fee of $75 per well plus a competitive industry rate for operations and field supervision.

The partnership will have the right to take in kind and separately dispose of its share of all oil and gas produced from its prospects, excluding its proportionate share of production required for lease operations and production unavoidably lost. Initially the partnership will designate the operator as its agent to market its production and authorize the operator to enter into and bind the partnership in those agreements as it deems in the best interest of the partnership for the sale of its oil and/or gas. If pipelines we have built by us are used in the delivery of natural gas to market, we may charge a gathering fee not to exceed that which would be charged by a non-affiliated third party for a similar service.

The production and accounting charges may be adjusted annually beginning January 1, 2007 to an amount equal to the rates initially established by the drilling and operating agreement, multiplied by the ratio of the then current average weekly earnings of Crude Petroleum and Gas Production workers to the average weekly earnings of Crude Petroleum and Gas Production workers for 2004, as published by the United States Department of Labor, Bureau of Labor Statistics, provided that the charge may not exceed the rate which would be charged by the comparable operators in the area of operations.

The drilling and operating agreement will continue in force so long as any well or wells produce, or are capable of production, and for an additional period of 180 days from cessation of all production.

Production Phase of Operations

The partnership will sell the produced gas to industrial users, gas brokers, interstate pipelines, or local utilities, subject to market sensitive contracts in which the price of gas sold will vary as a result of market forces.

The partnership may enter into fixed price contracts or use financial hedges to reduce the variability of cash flow resulting from increases and decreases in gas and oil prices, which may result in greater or lower cash flow than if hedges were not used.

- The partnership will not complete contracts for sale of gas until after drilling of the wells.

- Oil will be sold to local purchasers at spot prices.

General. Once the partnership's wells are "completed" (i.e., all surface equipment necessary to control the flow of, or to shut down, a well has been installed, including the gathering pipeline), production operations will commence. The partnership will not complete contracts for sale of gas or oil until after drilling of the wells, except as noted below.

The partnership will sell the produced gas to industrial users, gas marketers, including affiliated marketers, commercial end users, interstate or intrastate pipelines or local utilities, primarily under market sensitive contracts in which the price of gas sold will vary as a result of market forces. Some leases, and thus the gas derived from wells drilled on those leases, may be dedicated to particular markets at the time we acquire those leases.

The partnership may enter into fixed price contracts, or utilize derivatives, including hedges, swaps or options in order to offset some or all of the price variability for particular periods of time, generally for less than one year. The use of derivatives may entail fees, including the time value of money for margin requirements, which will be charged to the partnership.

We may utilize our subsidiary Riley Natural Gas to market gas, enter into hedges or swaps, or purchase options on behalf of the partnership. Riley Natural Gas will be entitled to charge reasonable fees for its services, including out-of-pocket costs. These fees, however, will be equal to or less than fees charged to non-affiliated producers for similar services.

Seasonal factors, such as effects of weather on costs, may impact the partnership's results. In addition, both sales volumes and prices tend to be affected by demand factors with a significant seasonal component.

Expenditure of Production Revenues. The partnership's share of production revenue from a given well will be burdened by and/or subject to royalties and overriding royalties, monthly operating charges, taxes and other operating costs.

The above items of expenditure involve amounts payable solely out of, or expenses incurred solely by reason of, production operations. Although the partnership is permitted to borrow funds for its operations (see "Risk Factors –The partnership may borrow funds if needed for partnership operations to fully develop the partnership's wells;if full development of the partnership’s wells proves commercially unsuccessful, an investor might anticipate a reduction in cash distributions" and "Source of Funds and Use of Proceeds – Subsequent Source of Funds" for a discussion of the implications of the partnership's funding capabilities), it is our practice to deduct operating expenses from the production revenue for the corresponding period, and to defer the collection of operating expenses when revenues are insufficient to render full payment.

Interests of Parties

We, investor partners, and unaffiliated third parties (including landowners) share revenues from production of gas and oil from wells in which the partnership has an interest. The following chart expresses the interest of gross revenues derived from the wells. For the purpose of this chart, "gross revenues" is defined as the "Well Head Gas and Oil Revenue" paid by the purchasers. In the event the partnership acquires less than a 100% working interest, the percentages available to the partnership will decrease proportionately. Landowner and other royalty interests payable to unaffiliated third parties may vary, provided that the average of the royalty interests for all prospects of a partnership shall not exceed 25%. The revenues to be distributed are subject to the revised sharing arrangement policy and to revisions if we make a capital contribution greater than our 24.4% requirement. See "Participation in Costs and Revenues" for a discussion of how revenue distributions might be revised as we reference in the preceding sentence.

Program Revenue Sharing			
		Partnership Net Working Interest Third Party Royalties	
	Entity Interest	If 12½%	If 25%
Managing General Partner	25% Partnership Interest	21.875%	18.75%
Investor Partners	75% Partnership Interest	65.625%	56.25%
Third Parties	Landowners and Over-riding Royalties	12.50%	25.00%
		100.00%	100.00%

Insurance

The Managing General Partner will carryliability insurance of not less than $10 million during drilling operations and will maintain other insurance as appropriate.

The Managing General Partner has a good faith duty to provide insurance coverage, sufficient, in its judgment, to protect the Investors against the foreseeable risks of drilling.

Increasing cost of insurance could reduce partnership funds available for drilling.

We, in our capacity as operator, will carry pollution, public liability and workmen's compensation insurance, but that insurance may not be sufficient to cover all liabilities. Each unit held by the additional general partners represents an open-ended security for unforeseen events such as blowouts, lost circulation, stuck drillpipe, etc., which may result in unanticipated additional liability materially in excess of the per unit subscription amount.

We have obtained various insurance policies, as described below, and intend to maintain these policies subject to our analysis of their premium costs, coverage and other factors. We may, in our sole discretion, increase or decrease the policy limits and types of insurance from time to time as we deem appropriate under the circumstances, which may vary materially. We have obtained and expect to maintain the following types and amounts of insurance. We are the beneficiary under each policy and pay the premiums for each policy, except the Managing General Partner and the partnership are co-insured and co-beneficiaries with respect to the insurance coverage referred to in #2 and #5 below. Additionally, we as operator of the partnerships' wells require all of our subcontractors to carry varying amounts of liability insurance coverage with respect to their activities. In the event of a loss, the insurance policies of the particular subcontractor at risk would be drawn upon before the insurance of the Managing General Partner or that of the partnership.

1. Workmen's compensation insurance in full compliance with the laws for the States of West Virginia, Michigan, Pennsylvania and Colorado; this insurance will be obtained for any other jurisdictions where a partnership conducts its business;

2. Operator's bodily injury liability and property damage liability insurance, each with a limit of $1,000,000;

3. Employer's liability insurance with a limit of not less than $1,000,000;

4. Automobile public liability insurance with a limit of not less than $1,000,000 per occurrence, covering all automobile equipment; and

5. Operator's umbrella liability insurance with a limit of $80,000,000 for each well location.

We, as Managing General Partner and operator, have determined in good faith, in the exercise of our fiduciary duty as Managing General Partner and as operator, that adequate insurance has been obtained on behalf of the partnerships to provide the partnership with the coverage as we believe is sufficient to protect the investor partners against the foreseeable risks of drilling. We will obtain and maintain public liability insurance, including umbrella liability insurance, of at least two times the Partnership's capitalization, but in no event less than $10 million during drilling operations. If two partnerships are conducting drilling activities simultaneously, as provided for under "Proposed Activities – Introduction" above, and the investor capital of the partnerships is in excess of $25 million in the aggregate, we will obtain additional liability insurance coverage, up to a maximum of $50 million, during drilling in order to provide what we believe to be sufficient insurance coverage with respect to the total capitalization of those partnerships which are conducting simultaneous drilling activities. We will maintain the two-times insurance coverage during its drilling activities up to a maximum coverage of $50 million. We will review the partnership insurance coverage prior to commencing drilling operations and periodically evaluate the sufficiency of insurance. We will obtain and maintain our insurance coverage as we determine to be commensurate with the level of risk involved. In more than 36 years of operations, drilling more than2,600 wells in Tennessee, Ohio, Pennsylvania, Michigan, Colorado, North Dakota, Montana, Utah, Wyoming and West Virginia, our largest insurance claim has been less than $80,000.

The annual cost of the insurance to the partnership is estimated to be approximately $625 per well in the year that it is drilled and approximately $140 per each producing well for the partnership liability and other insurance coverages. The costs of insurance are allocated based primarily upon the level of drilling operations. Insurance premiums may increase in the future. The primary effect of increasing premiums cost is to reduce funds otherwise available for partnership drilling operations or for distribution to investors.

We will notify all additional general partners at least 30 days prior to any material change in the amount of the insurance coverage. Within this 30-day period and otherwise after the expiration of one year following the closing of the offering with respect to a particular partnership, additional general partners have the right to convert their units into units of limited partnership interest by giving written notice to us and will have limited liability for any partnership operations conducted after the conversion date as a limited partner effective upon the filing of an amendment to the certificate of limited partnership of a partnership. At any time during this 30-day period, upon receipt of the required written notice from the additional general partner of his intent to convert, we will amend the limited partnership agreement and will file an amendment with the State of West Virginia prior to the effective date of the change in insurance coverage and effectuate the conversion of the interest of the former additional general partner to that of a limited partner.

The Managing General Partner's Policy Regarding Roll-Up Transactions

Although we have no intention of engaging the partnership in a "roll-up" transaction, it is possible at some indeterminate time in the future that the partnership will become so involved. In general, a roll-up means a transaction involving the acquisition, merger, conversion, or consolidation, directly or indirectly, of the partnership with or into another partnership, corporation or other entity, which we refer to as the "roll-up entity" and the issuance of securities by the roll-up entity to investor partners. A roll-up will not include a transaction involving the conversion to corporate, trust or association form of only the partnership if, as a result of the transaction, there is no significant adverse change in the voting rights of the investor partners, the term of existence of the partnership, our compensation, or the investment objectives of the partnership. The determination of "significant adverse change" will be made solely by us in the exercise of our reasonable business judgment as manager of the partnership and consistent with our obligations as a fiduciary to the investor partners.

The limited partnership agreement provides various policies in the event that a roll-up should occur in the future. These policies include:

- An appraisal of all partnership assets will be obtained from a competent independent expert, and a summary of the appraisal will be included in a report to the investor partners in connection with a proposed roll-up;
- Any participant who votes "no" on the proposal will be offered a choice of:
    - accepting the securities of the roll-up entity offered in the proposed roll-up; or
    - either (a) remaining an investor partner in the partnership and preserving his or her interests in the partnership on the same terms and conditions as existed previously, or (b) receiving cash in an amount equal to his or her pro-rata share of the appraised value of the partnership's net assets;
- The partnership will not participate in a proposed roll-up
    - which would result in the diminishment of an investor partner's voting rights under the roll-up entity's chartering agreement;
    - in which the investor partners' right of access to the records of the roll-up entity would be less than those provided by the limited partnership agreement; or
    - in which any of the costs of the transaction would be borne by the partnership if the proposed roll-up is not approved by the investor partners.
    - The limited partnership agreement further provides that the partnership will not participate in a roll-up transaction unless the roll-up transaction is approved by at least 66 2/3% in interest of the investor partners. See Section 5.07(m) of the limited partnership agreement.

COMPETITION, MARKETS AND REGULATION

Competition is intense in all phases of the oil and gas industry, including the acquisition of prospects and the sale of production.

Competition for equipment and services is keen and can adversely affect drilling costs and the timing of drilling.

Excess supplies and competition have depressed gas and oil prices at times, and there is no way to predict when unfavorable conditions may exist in the future.

The partnership expects to sell its gas and oil subject to market sensitive contracts, so the price of gas and oil sold will vary as a result of market forces.

Competition and Markets

Competition is keen among persons and companies involved in the exploration for and production of oil and gas. The partnership will encounter strong competition at every phase of its business including acquiring properties suitable for exploration and development and marketing of oil and gas. It will compete with entities having financial resources and staffs substantially larger than those available to the partnership. There are thousands of oil and gas companies in the United States. The national supply of natural gas is widely diversified. As a result of this competition and Federal Energy Regulatory Commission ("FERC") and Congressional deregulation of gas and oil prices, prices are generally determined by competitive forces.

There will also be competition among operators for drilling equipment, tubular goods, and drilling crews. The competition may affect the ability of each partnership to acquire leases suitable for development by the partnerships and to develop expeditiously the leases once they are acquired.

The marketing of any oil and gas produced by a partnership will be affected by a number of factors which are beyond the partnership's control and whose exact effect cannot be accurately predicted. These factors include the volume and prices of crude oil imports, the availability and cost of adequate pipeline and other transportation facilities, the marketing of competitive fuels, such as coal and nuclear energy, and other matters affecting the availability of a ready market, such as fluctuating supply and demand. Among other factors, the supply and demand balance of crude oil and natural gas in world markets have caused significant variations in the prices of these products over recent years.

FERC Order No. 636, issued in 1992, restructured the natural gas industry by requiring pipelines to separate their storage, sales and transportation functions and establishing an industry-wide structure for "open-access" transportation service. Order No. 637, issued in February 2000, further enhanced competitive initiatives, by removing price caps on short-term capacity release transactions.

The accelerating deregulation of natural gas and electricity transmission has caused, and may continue to cause, a convergence of the gas and electric industries. CNG Transmission, which has purchased partnership production in the past, is an example of this convergence, having completed its merger with Dominion Resources, Inc., a large, Virginia-based provider of electric services, in January 2000. Demand for natural gas by the electric power sector is expected to increase through the next decade, according to the United States Energy Information Administration. Increased competition, particularly where coupled with the enforcement of stringent environmental regulations, may increase the electric industry's reliance on natural gas.

Order No. 637 also enacted other regulatory policies that increase the flexibility of interstate gas transportation, maximize shippers' supply alternatives, and encourage domestic natural gas production in order to meet projected increases in natural gas demand. These increases in demand will come from a number of sources, including as boiler fuel to meet increase electric power generation needs and as an industrial fuel that is environmentally preferable to alternatives such as nuclear power and coal. This trend has been evident over the past year, particularly in the western U.S., where natural gas is the preferred fuel for environmental reasons, and electric power demand has directly affected demand for natural gas.

Beginning in 1995, the North American Free Trade Agreement ("NAFTA") eliminated trade and investment barriers in the United States, Canada, and Mexico, increasing foreign competition for natural gas production. Legislation that Congress may consider with respect to oil and gas may increase or decrease the demand for the partnerships' production in the future, depending on whether the legislation is directed toward decreasing demand or increasing supply.

Members of the Organization of Petroleum Exporting Countries establish prices and production quotas for petroleum products from time to time, with the intent of reducing the current global oversupply and maintaining or increasing price levels. We are unable to predict what effect, if any, future OPEC actions will have on the quantity of, or prices received for, oil and gas produced and sold from the partnerships' wells.

Various parts of the prospect area are crossed by pipelines belonging to Colorado Interstate Gas, Encana, Duke, Williams and others. These companies have all traditionally purchased substantial portions of their supply from Colorado producers. In addition, all are subject to regulations enacted by state commissions or the FERC which require them to transport gas for others. Transportation on these systems requires that delivered gas meet quality standards and that a tariff be paid for quantities transported.

The partnership expects to sell gas from its wells to Duke Energy, Encana and Williams on the spot market via open access transportation arrangements through Colorado Interstate Gas, Williams or other pipelines. As a result of FERC regulations that require interstate gas pipelines to separate their merchant activities from their transportation activities and require them to release available capacity on both a short- and a long-term basis, local distribution companies must take an increasingly active role in acquiring their own gas supplies. Consequently, pipelines and local distribution companies are buying gas directly from gas producers and marketers, and retail unbundling efforts are causing many end-users to buy their own reserves. Activity by state regulatory commissions to review local distribution company procurement practices more carefully and to unbundle retail sales from transportation has caused gas purchasers to minimize their risks in acquiring and attaching gas supply and has added to competition in the natural gas marketplace.

In Order No. 587 and other initiatives, FERC required pipelines to develop electronic communications in order to ensure that the gas industry is more competitive. Pipelines must provide standardized access via the Internet to information concerning capacity and prices, and standardized procedures are now available for nominating and scheduling deliveries. The industry has also developed methods to access and integrate all gas supply and transportation information on a nationwide basis, via the Internet, so as to create a national market. Furthermore, parallel developments toward an electronic marketplace for electric power, mandated by the FERC in Order Nos. 888 and 2000, are serving to create multi-national markets for energy products generally. These systems will allow rapid consummation of natural gas transactions. Gas purchased in West Virginia, could, for example, be used in Seattle. Although this system may initially lower prices due to increased competition, it is anticipated to expand natural gas markets and to improve the reliability of the markets.

Natural Gas Pricing

The Managing General Partner anticipates that the partnerships' gas will be sold at fair market value.

The partnership may enter into fixed price contracts or use financial hedges to fix gas prices, which may result in greater or lower prices than market sensitive prices.

We anticipate selling the gas and oil from partnership wells in Colorado subject to market sensitive contracts, the price of which will increase or decrease with market forces beyond our control. Currently and in the past, we have sold the gas in the Piceance Basin primarily to Williams Production RMT, which has an extensive gathering and transportation system in the field. In Wattenberg Field, the gas is sold to Duke Energy Field Services, which gathers and processes the gas and liquefiable hydrocarbons produced, or to Encana. The oil is sold primarily to Teppco. Gas produced in Colorado is subject to changes in market prices on a national level, as well as changes in the market within the Rocky Mountain Region. Sales may be affected for short periods of time by capacity interruptions on pipelines transporting gas out of the region.

The PDC-sponsored partnerships have sold natural gas over the period May 1, 2002 through May 31, 2005 at prices ranging from $2.58 per Mcf to $12.22 per Mcf in the Appalachian Basin, $2.41 per Mcf to $7.88 per Mcf in Michigan, and $0.95 per Mcf to $8.95 per Mcf in the Rocky Mountain region. In the past, natural gas produced by the partnerships in the Rocky Mountain region has sold for less than the partnerships' prices received in the Appalachian and Michigan basins, but the partnerships' Rocky Mountain region development costs have been less than the costs per Mcfe of development in the Appalachian and Michigan basins. Notwithstanding this experience by previous PDC-sponsored partnerships, there can be no assurance that the partnership will receive similar prices for, or incur similar development costs in, its natural gas production.

Sale of natural gas by the partnerships will be subject to regulation by governmental regulatory agencies. Generally, the regulatory agency in the state where a producing gas well is located supervises production activities and the transportation of gas sold into intrastate markets. The FERC regulates the rates for interstate transportation of natural gas but, under the Wellhead Decontrol Act of 1989, FERC may not regulate the price of gas. Deregulated gas production may be sold at market prices determined by supply, demand, Btu content, pressure, location of wells, and other factors.

Regulation

Federal and state laws and regulations have a significant impact on drilling and production operations.

Environmental protection regulations may necessitate significant capital outlays by the partnership.

Federal and state regulations will affect production of partnership oil and gas. In most areas of operations, the production of oil is regulated by conservation laws and regulations, which set allowable rates of production and otherwise control the conduct of oil operations.

The partnership's drilling and production operations will also be subject to environmental protection regulations established by federal, state, and local agencies, which in turn may necessitate significant capital outlays which would materially affect the financial position and business operations of the partnership (see "Risk Factors – Environmental hazards involved in drilling gas and oil wells may result in substantial liabilities for the partnership").

Some states control production 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. Through regulations enacted to protect against waste, conserve natural resources and prevent pollution, local, state and federal environmental controls will also affect partnership operations. These regulations could affect partnership operations and could necessitate spending funds on environmental protection measures, rather than on drilling operations. If any penalties or prohibitions were imposed on a partnership for violating those regulations, that partnership's operations could be adversely affected.

In prior programs, expenses associated with compliance with environmental regulations have represented approximately 10-15% of the cost of drilling and completing wells, and it is expected that similar costs will be incurred in this program. These costs are included in the footage-based rates described at "Proposed Activities – Drilling and Operating Agreement," above.

Proposed Regulation

Various legislative proposals in Congress and in state legislatures could, if enacted, affect the petroleum and natural gas industries. These proposals involve, among other things, imposition of direct or indirect price limitations on natural gas production, expansion of drilling opportunities in areas that would compete with partnership production, imposition of land use controls (such as prohibiting drilling activities on federal and state lands in roadless wilderness areas), landowners' "rights" legislation, alternative fuel use requirements and/or tax incentives and other measures. At the present time, it is impossible to predict what proposals, if any, will actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals will have on the partnerships' operations.

MANAGEMENT

General Management

The Managing General Partner of the partnership is Petroleum Development Corporation ("PDC"), a publicly-owned Nevada corporation organized in 1955. The common stock of PDC is traded on the Nasdaq National Market. Since 1969, PDC has been engaged in the business of exploring for, developing and producing oil and natural gas primarily in West Virginia, Tennessee, Pennsylvania, Ohio, Michigan and the Rocky Mountains. As of May 1, 2005, PDC had approximately 120 employees. PDC will make available to investor partners, upon request, audited financial statements of PDC for the most recent fiscal year and unaudited financial statements for interim periods. PDC's Internet address is www.petd.com. PDC posts on its Internet Web site its periodic and current reports and other information that it files with the SEC.

We will actively manage and conduct the business of the partnerships, devoting our time and talents to management as we shall deem reasonably necessary. We will have the full and complete power to do any and all things necessary and incident to the management and conduct of each partnership's business. We will be responsible for maintaining partnership bank accounts, collecting partnership revenues, making distributions to the partners, delivering reports to the partners, and supervising the drilling, completion, and operation of the partnerships' natural gas and oil wells.

In addition to managing the affairs of the partnership, the management and technical staff of PDC also manage the corporate affairs of the company, the affairs of 74 limited partnerships formed in the current and previous programs, and other joint ventures formed over the years. We own an interest in all of the older limited partnerships and wells in addition to the interest we will purchase in the PDC 2004-2006 Drilling Program partnerships. Since we must divide our attention and efforts among many unrelated parties, your partnership will not receive our full attention or efforts at all times.

Experience and Capabilities as Driller/Operator

PDC will act as driller/operator for the program wells. Since 1969 PDC has drilled over 2,600 wells in Colorado, West Virginia, Tennessee, Ohio, Michigan, North Dakota, Utah, Wyoming, and Pennsylvania. PDC currently operates approximately 2,700 wells.

PDC employs geologists who develop prospects for drilling by PDC and who help oversee the drilling process. In addition, PDC has an engineering staff that is responsible for well completions, pipelines, and production operations. PDC retains drilling subcontractors, completion subcontractors, and a variety of other subcontractors in the performance of the work of drilling contract wells. In addition to technical management, PDC may provide services, at competitive rates, from PDC-owned service rigs, a water truck, steel tanks used temporarily on the well location during the drilling and completion of a well, roustabouts, and other assorted small equipment and services. A roustabout is an oil and gas field employee who provides skilled general labor for assembling well components and other similar tasks. PDC may lay short gathering lines, or may subcontract all or part of the work where it is more cost effective for a partnership. PDC employs full-time welltenders and supervisors to operate its wells. In addition, the engineering staff evaluates reserves of all wells at least annually and reviews well performance against expectations. All services provided by us are provided at rates less than or equal to prevailing rates for similar services provided by unaffiliated persons in the area.

Petroleum Development Corporation

The executive officers, directors and key technical personnel of PDC, their principal occupations for the past five years and additional information are set forth below:

Name	Age	Positions and Offices Held	Held Current Position Since
Steven R. Williams	54	Chairman, Chief Executive Officer, Director	January 2004 March 1983
Thomas E. Riley	52	President Director	December 2004 January 2004
Eric R. Stearns	47	Executive Vice President –Exploration and Development	November 2003
Darwin L. Stump	50	Chief Financial Officer and Treasurer	November 2003
Gregory A. Morgan	46	Secretary	September 2004
Vincent F. D'Annunzio	53	Director	February 1989
Jeffrey C. Swoveland	50	Director	March 1991
Donald B. Nestor	56	Director	March 2000
Kimberly Luff Wakim	47	Director	January 2003
David C. Parke	38	Director	November 2003
Joseph C. Giampetroni	46	Vice President-Finance and Business Development	May 2005
Celesta M. Miracle	36	Vice President, Investor Relations	February 2004
Ersel E. Morgan	61	Vice President – Production	April 1995
Janet W. Potter	47	Corporate Controller	November 2003
Alan Smith	47	Senior Geologist	April 1980
Bob Williamson	51	Geologist	February 1991

Name	Age	Positions and Offices Held	Held Current Position Since
Susan Foster	44	Senior Engineer	June 1997
Tom Carpenter	53	Senior Geologist	December 1997
Dewey Gerdom	46	Western Region Manager	August, 2000
Steve Trippett	48	Engineer	June 1984
Jeffrey T. Davis	49	Production Operations Manager	August 1999

Steven R. Williams was elected Chairman and Chief Executive Officer of PDC in January 2004, following the retirement of James N. Ryan and has served as President of PDC from 1983 to 2004 and Director since 1983.

Thomas E. Riley has served as President since December 2004 and Executive Vice President of Production, Natural Gas Marketing and Business Development from November 2003 to December 2004. Prior thereto, Mr. Riley served as Vice President - Gas Marketing and Acquisitions of PDC from April 1996 to November 2003. Prior to joining PDC, Mr. Riley was president of Riley Natural Gas Company, a natural gas marketing company, from its inception in 1987. PDC acquired Riley Natural Gas in April 1996. Mr. Riley continues to serve as president of PDC's wholly-owned subsidiary. A registered professional engineer, Mr. Riley received a BS degree in petroleum engineering from West Virginia University in 1974.

Eric R. Stearns was appointed Executive Vice President of Exploration and Development in November 2003. Prior thereto, Mr. Stearns was Vice President-Exploration and Development from April 1995 to November 2003. Mr. Stearns joined PDC in 1985 after working for Hywell, Incorporated , and for Petroleum Consultants, Inc. between 1981 and 1985. Mr. Stearns received a BS degree in geology from Virginia Polytechnic Institute and State University in 1981.

Darwin L. Stump has been an officer of PDC since April 1995 and held the position of Corporate Controller from 1980 to November 2003. Mr. Stump was appointed Acting Chief Financial Officer of PDC in October 2003 following the death of Dale G. Rettinger. The board of directors named Mr. Stump CFO in November 2003. Prior to joining PDC, Mr. Stump was a senior accountant with Main Hurdman, Certified Public Accountants. Mr. Stump is a CPA, a member of the AICPA, the West Virginia Society of CPAs and a graduate of West Virginia University with a B.S. degree in accounting.

Gregory A. Morgan is a partner in the Clarksburg, West Virginia law firm of Young Morgan & Cann, PLLC. He was elected corporate secretary of PDC in September 2004. He graduated from West Virginia University in 1980, and from the West Virginia College of Law in 1983. He served as an Assistant Attorney General of West Virginia from 1983 to 1986. He currently also serves as Clarksburg’s City Attorney.

Vincent F. D'Annunzio has served as president of Beverage Distributors, Inc., located in Clarksburg, West Virginia since 1985.

Jeffrey C. Swoveland has served as Chief Financial Officer of Body Media, Inc., Pittsburgh, Pennsylvania since September 2000. Prior thereto, Mr. Swoveland was Vice President-Finance and

Treasurer of Equitable Resources, Inc. since September 1994. Mr. Swoveland received an MS degree in finance from Carnegie Mellon University.

Donald B. Nestor is a Certified Public Accountant and a Partner in the CPA firm of Toothman, Rice, P.L.L.C. and is in charge of the firm's Buckhannon, West Virginia office. Mr. Nestor has served in that capacity since 1975.

Kimberly Luff Wakim an attorney and a CPA, is a Partner with the Pittsburgh, Pennsylvania law firm, Thorp, Reed & Armstrong LLP, where she serves as a member of the Executive Committee. Ms. Wakim has practiced law with Thorp, Reed & Armstrong LLP since 1990.

David C. Parkejoined Mufson/Howe/Hunter & Company LLC, an investment banking firm focused on the needs of emerging growth and middle market companies, as a founder and director in 2003. From 1992 to 2003, Mr. Parke was director of the corporate finance department of Investec, Inc. and its predecessor Pennsylvania Merchant Group Ltd., investment banking companies. Prior to joining Pennsylvania Merchant Group, Mr. Parke served in the corporate finance departments of Wheat First Butcher & Singer, now part of Wachovia Securities, and Legg Mason, Inc. Mr. Parke received his MBA with honors from The Wharton School of the University of Pennsylvania and graduated summa cum laude and Phi Beta Kappa from Lehigh University with a BS in finance.

Joseph C. Giampetroni joined PDC in May 2005 as Vice President of Finance and Business Development. Prior to joining PDC, Mr. Giampetroni was employed by JP Morgan Securities, Inc. and its predecessors for more than 20 years serving primarily as a corporate and investment banking client executive dedicated to the energy sector. Mr. Giampetroni is a graduate of Eastern Michigan University with a BBA in Finance and Economics and is a Series 7 and Series 63 registered representative.

Celesta M. Miracle joined PDC in February 2004 as Vice President of Investor Relations. Prior to joining PDC, Ms. Miracle was an Investment Representative with Edward Jones Investments for three years. Prior thereto, she had ten years of oil and gas experience with Dominion Resources, where her focus was primarily in the regulatory area. Ms. Miracle graduated summa cum laude with a B.S. degree in accounting from West Virginia University.

Ersel E. Morgan was elected Vice President-Production in April 1995. He joined PDC as a landsman in 1980.

Janet W. Potter has been Corporate Controller since November 2003. Ms. Potter joined PDC in 1989 as a senior accountant and served as Assistant Controller since 1990. Prior to joining PDC, Ms. Potter worked as an accountant with Cunningham, Lively and Carpenter and with Tetrick and Bartlett. She has a B.S. degree in accounting, is a CPA and a member of the AICPA and the West Virginia Society of CPAs.

Alan Smith joined PDC in April 1980 as a geologist in the Tennessee Division. He has a BS degree in geology from Tennessee Technological University.

Bob Williamson joined PDC in February 1991, as a geologist. Mr. Williamson received a B.S. degree in geology from West Virginia University in 1980. Prior to joining PDC, he worked as a geologist for Ramco in Belpre, Ohio, for nearly nine years on projects in West Virginia, Kentucky, Kansas, and Oklahoma.

Susan Foster joined PDC in June 1997, as a petroleum engineer. Ms. Foster has a BS degree in petroleum engineering from Pennsylvania State University. Prior to joining PDC, Ms. Foster worked as a petroleum engineer in the Appalachian Basin withPenn Virginia and Equitable Resources.

Tom Carpenter joined PDC in December 1997 as a senior geologist. Mr. Carpenter has a B.A. degree in geology from Miami University of Ohio and an M.S. degree in geology from West Virginia

University. Prior to joining PDC, Mr. Carpenter was employed as Manager of Exploration and Development of Alamco, Inc. from 1996-1997, and by Ashland Exploration, Inc. and Shell Oil Company.

Dewey Gerdom joined PDC in August, 2000 as Manager of our Colorado office. Prior to joining the Company, Mr. Gerdom has over 24 years of experience in the industry including 15 years with Chevron.

Steve Trippett joined PDC in June, 1984. For the past12 years he has worked as a completion engineer for the Company, including the past 4 years in our Colorado office.

Jeffrey T. Davis joined PDC in June 1998 as a field supervisor in Pennsylvania. He is currently the production manager for PDC's Colorado operations. Prior to joining PDC, Mr. Davis worked for Fustos Energy Services and Shawmut Development Corporation in a supervisory position.

Certain Shareholders of Petroleum Development Corporation

The following table sets forth information as of March 31, 2005, with respect to the common stock of PDC owned by each person who owns beneficially 5% or more of the outstanding voting common stock, by all directors and executive officers individually, and by all directors and officers as a group.

Name and Address	Beneficial Ownership (1)	
	Number	Percent
Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 94105	2,197,003(2)	13.2%
Fidelity Management 82 Devonshire Street Boston, MA 02109	1,536,000(3)	9.3%
Steven R. Williams 103 East Main Street Bridgeport, WV 26330	402,156	2.5%
Thomas E. Riley 103 East Main Street Bridgeport, WV 26330	93,197	*
Darwin L. Stump 103 East Main Street Bridgeport, WV 26330	20,450	*
Eric R. Stearns 103 East Main Street Bridgeport, WV 26330	50,000	*
Vincent F. D'Annunzio	15,838	*
Jeffrey C. Swoveland	12,342	*
Donald B. Nestor	1,143	*
Kimberly Luff Wakim	1,300	*

Name and Address	Beneficial Ownership (1)	
	Number	Percent
David C. Parke	852	*
All directors and executive officers as a group (9 persons)	624,658	3.8%

* Less than 1%

(1) Includes shares over which the person currently holds or shares voting or investment power. Unless otherwise indicated in the footnotes to this table, the persons named in this table have sole voting and investment power with respect to the shares beneficially owned. The percentage column is based upon 16,589,824 shares of PDC common stock outstanding as of March 31, 2005.

(2) According to the Schedule 13G filed by Barclay Global Investors, NA with the Securities and Exchange Commission on February 14, 2005.

(3) According to the Schedule 13G filed by Fidelity Management with the Securities and Exchange Commission on February 14, 2005.

Remuneration

None of our officers or directors will receive any direct remuneration or other compensation from the partnerships. These persons will receive compensation solely from PDC. Information as to compensation paid by us to our directors and executive officers may be obtained from publicly available reports filed by us with the Securities and Exchange Commission under the Securities Exchange Act of 1934.

Legal Proceedings

We as driller/operator are subject to minor legal proceedings arising from the normal course of business. These legal actions are not considered material to the operations of the partnership or us.

CONFLICTS OF INTEREST

The Managing General Partner currently manages and in the future will sponsor and manage natural gas and oil drilling programs similar to the partnerships.

The Managing General Partner decides which prospects each partnership will acquire.

The Managing General Partner will act as operator of the partnership wells; the terms of the drilling and operating agreement have not been negotiated by non-affiliated persons.

The Managing General Partner will provide drilling and completion services with respect to partnership wells.

The Managing General Partner is general partner of numerous other partnerships, and owes duties of good-faith dealing to its other partnerships.

The Managing General Partner and affiliates engage in significant drilling, operating, and producing activities for other partnerships.

The partnerships are subject to various conflicts of interest arising out of their relationship with us. These conflicts include, but are not limited to, the following:

Future Programs by Managing General Partner and Affiliates. We have the right and expect to continue to organize and manage oil and gas drilling programs in the future similar to the partnerships of the program, and to conduct operations now and in the future, jointly or separately, on our own behalf or for other private or public investors. Affiliates of ours also intend to conduct those activities on their own behalf. Officers, directors and employees of ours have participated, and will participate in the future, at cost, in working interests in wells in which we and our partnerships participate. To the extent that we engage in these activities or that our affiliates invest in the partnerships or other partnerships sponsored by us, conflicts of interest will arise.

Fiduciary Responsibility of the Managing General Partner. We are accountable to the partnership as a fiduciary and consequently have a duty to exercise good faith and to deal fairly with the investors in handling the affairs of the partnership. We are also accountable as a fiduciary to the other partnerships which we have sponsored and for which we act as managing general partner, and therefore we have a duty to exercise good faith and deal fairly with the investors of those partnerships. While we will endeavor to avoid conflicts of interest to the extent possible, conflicts nevertheless may occur and, in that event, our actions may not be most advantageous to the partnership and could fall short of the full exercise of our fiduciary duty. If we should breach our fiduciary responsibilities, you would be entitled to an accounting and to recover any economic losses caused by our breach, only after either proving a breach in court or reaching a settlement with us.

Independent Representation in Indemnification Proceeding. Counsel to the partnership and to us in connection with this offering are the same. This dual representation will continue in the future. However, in the event of an indemnification proceeding between the partnership and us, we will cause the partnership to retain separate and independent counsel to represent its interest in the proceeding.

Due Diligence Review. PDC Securities Incorporated, the dealer manager of the offering, is our affiliate and its due diligence examination concerning this offering cannot be considered to be independent. See "Plan of Distribution" for a discussion of the procedures involved in the offering of the units for sale.

Managing General Partner's Interest. Although we believe that our interest in partnership profits, losses, and cash distributions is equitable (see "Participation in Costs and Revenues" for a discussion of the allocation of the revenue and expense items of the partnership), our interest was not determined by arm's-length negotiation.

Transactions between the Partnership and Operator. We will also act as operator. Accordingly, although we believe the terms of the drilling and operating agreement will be equitable, it will not be the subject of arm's-length negotiation. Furthermore, we may be confronted with a continuing conflict of interest with respect to the exercise and enforcement of the rights of the partnership under that agreement. See "Transactions with the Managing General Partner or Affiliates," below.

Conflicting Drilling Activities. Our affiliates have engaged in significant drilling and producing activities for the accounts of affiliated partnerships related to previous drilling programs. In addition, we and our affiliates manage and operate natural gas and oil properties for investors in other drilling programs. Although the limited partnership agreement attempts to minimize any potential conflicts, we will be in a position to decide whether a natural gas or oil property will be retained or acquired for the account of the partnership or other drilling programs which we or our affiliates may presently operate or operate in the future.

Conflicts with Other Programs. We realize that our conduct and the conduct of our affiliates in connection with the other drilling programs which we have sponsored could give rise to a conflict of interest between the position of PDC as Managing General Partner of the partnership and the position of PDC or one of its affiliates as general partner or sponsor of additional programs. In resolving any conflicts, each partnership will be treated equitably with other partnerships on a basis consistent with the funds available to the partnerships and the time limitations on the investment of funds. However, no provision has been made for an independent review of conflicts of interest. We believe that the possibility of conflicts of interest between the partnership and prior programs is minimized by the fact that substantially all the funds available to prior drilling programs in which we or an affiliate serves as general partner have been committed to a specific drilling program.

We follow a policy of developing next what we judge to be the best available prospect. Acquisition of new leases and information derived from wells already drilled result in a constant change in this assessment. We anticipate that generally only one partnership will be actively engaged in drilling at any time. However, if more than one partnership has funds available for drilling, we will generally complete the operations for the first partnership before beginning the operations for the subsequent partnership.

The limited partnership agreement authorizes us to cause the partnership to acquire undivided interests in natural gas and oil properties, and to participate with other parties, including other drilling programs previously or subsequently conducted by us or our affiliates, in the conduct of exploration and drilling operations on those properties. Because we must deal fairly with the investors in all of our drilling programs, if conflicts between the interest of the partnership and other drilling programs do arise, we might not in every instance be able to resolve those conflicts to the maximum advantage of the partnership.

From time to time, we may cause partnership prospects to be enlarged or contracted on the basis of geological data to define the productive limits of any pool discovered. The partnership is not required to expend additional funds for the acquisition of property unless the acquisition can be made from the capital contributions. The limited partnership agreement does not permit the partnership to borrow money as may be required for its business. If the property is not acquired by the partnership, the partnership may lose a promising prospect. Except as otherwise provided by the limited partnership agreement, a prospect might be acquired by us or an affiliate or other drilling programs conducted by them.

In addition, subject to the restrictions set forth below, we in our sole discretion decide which prospects and what interest to transfer to the partnership. This may result in another drilling program sponsored by us acquiring property adjacent to partnership property. Another program could gain an advantage over the partnership by reason of the knowledge gained through the partnership's prior experience in the area or if the other drilling program were the first to discover or develop a productive pool of oil or natural gas.

Acquisition of Prospects. We have discretion in selecting leases to be acquired by the partnership from us or our affiliates or third parties and the location and type of operations which the partnership will conduct on the leases. Some leases may be part of our existing inventory, although no leases have been designated for inclusion in the partnership at the present time. Neither we nor any affiliate will retain undeveloped acreage adjoining a partnership prospect in order to use partnership funds to "prove up" the acreage owned for our own account.

Whenever we sell, transfer or convey an interest in a prospect to a particular partnership, we must, at the same time, sell to the partnership an equal proportionate interest in all of our leases in the same prospect (except any interests in producing wells). The term “prospect” generally means an area which is believed to contain commercially productive quantities of natural gas or oil. However, a prospect will be limited to the drilling or spacing unit on which one well will be drilled if the following two conditions are met:

- the well is being drilled to a geological feature which contains proved reserves as defined below, and

- the drilling or spacing unit protects against drainage.

The Managing General Partner believes that for a prospect located in areas as described in “Proposed Activities – Current Prospect Areas,” a prospect will consist of the drilling and spacing unit because it will meet the test in the preceding sentence. The Managing General Partner also anticipates that most prospect areas it might include in partnerships will also meet the test in the preceding paragraph.

"Proved reserves," generally, are the estimated quantities of natural gas and oil which have been demonstrated to be recoverable in future years with reasonable certainty under existing economic and operating conditions. Proved reserves include "proved undeveloped reserves" which generally are reserves expected to be recovered from existing wells where a relatively major expenditure is required for recompletion or from new wells on undrilled acreage. Reserves on undrilled acreage will 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.

In the prospect areas, we anticipate that the drilling of these wells by each partnership may provide us with offset sites by allowing us to determine, at the partnership's expense, the value of adjacent acreage in which the partnership would not have any interest. We own acreage throughout the areas where each partnership's wells will be situated. To lessen this conflict of interest, for five years we may not drill any well on a spacing unit adjoining any partnership well other than for future partnerships.

Other than prospects qualifying as described above, if we or an affiliate (except another affiliated limited partnership in which the interest of us or our affiliates is identical or less than their interest in the partnerships) subsequently proposes to acquire an interest in a prospect in which a partnership possesses an interest or in a prospect abandoned by the partnership within one year preceding the prospect acquisition, we or the affiliate will offer an equivalent interest to the partnership; and, if cash or financing is not available to the partnership to enable it to consummate a purchase of an equivalent interest in the property, neither we nor any of our affiliates will acquire the interest or property, but the term "affiliate" will not include another partnership where our or our affiliates' interest is identical to, or less than, their interest in the subject partnerships. The term "abandon" means the termination, either voluntarily or by operation of the lease or otherwise, of all of a partnership's interest in the prospect. These limitations will not apply after the lapse of five years from the date of formation of a partnership.

A sale, transfer or conveyance to the partnership of less than all of our or our affiliates' interest in any prospect is prohibited unless the interest retained by us or our affiliates is a proportionate working interest, the respective obligations of the partnership and us or our affiliates are substantially the same immediately after the sale of the interest, and our or our affiliates' interest in revenues does not exceed an amount proportionate to the retained working interest. Neither we nor our affiliates will retain any overriding royalty interests or other burdens on the lease interests conveyed to the partnerships, and will not enter into any farmout arrangements with respect to our retained interest, except to non-affiliated third parties.

The partnerships will acquire only those leases reasonably expected to meet the stated purposes of the partnerships. The partnerships will not acquire any lease for the purpose of a subsequent sale or farmout unless the acquisition is made after a well has been drilled to a depth sufficient to indicate that the acquisition would be in the partnerships' best interest. We expect that the partnership will develop substantially all of its leases and will farm out few, if any, leases. The partnerships will not farm out, sell or otherwise dispose of leases unless we, exercising the standard of a prudent operator, determine that:

- a partnership lacks sufficient funds to drill on the lease and cannot obtain suitable alternative financing;
- downgrading subsequent to a partnership's acquisition has rendered drilling undesirable;
- drilling would concentrate excessive funds in one location creating undue risk to a partnership; or
- the best interests of a partnership, based on the standard of a prudent operator, would be served by the disposition.

In the event of a farmout, we will retain for the partnerships the economic interests and concessions as a reasonably prudent operator would retain under the circumstances. We will not farm out a lease for the primary purpose of avoiding payments of our partnership share of costs of drilling on that lease. However, the decision with respect to making farmouts and the terms of a farmout involve conflicts of interest because we may benefit from cost savings and reduction of risk, and in the event of a farmout to an affiliated limited partnership or other affiliate, we or our affiliates will represent both related entities. A farmout is a drilling location or lease we get from another company (or individual) which has leased the rights to drill on the property from the owners of the oil and gas rights. We usually must pay a share of the revenue from this property to the company which provides the farmout in addition to the royalty payments due to the owners of the oil and gas rights.

Transactions with the Managing General Partner or Affiliates. We will furnish drilling and completion services with respect to some or all of the partnership wells. A subsidiary of ours may market gas produced from partnership wells. In addition, we will act as operator for the producing wells of the partnership. The prices to be charged the partnership for the supplies and services will be competitive with the prices of other unaffiliated persons in the same geographic area engaged in similar businesses.

Neither we nor any affiliate will render to the partnership any natural gas or oil field, equipage or other services nor sell or lease to the partnership any equipment or related supplies unless the person is engaged, independently of the partnership and as an ordinary and ongoing business, in the business of rendering the services or selling or leasing the equipment and supplies to a substantial extent to other persons in the natural gas and oil industry in addition to partnerships in which we or our affiliate has an interest, or, if that person is not engaged in that business then the compensation, price or rental will be the cost of the services, equipment or supplies to that person or the competitive rate which could be obtained in the area, whichever is less. Notwithstanding any provision to the contrary, we and our affiliates may not profit by drilling in contravention of our fiduciary obligations to the investor partners. Any services not otherwise described in this prospectus for which we or any of our affiliates are to be compensated will be embodied in a written contract which precisely describes the services to be rendered and the compensation to be paid.

All benefits from marketing arrangements or other relationships affecting the property of us or our affiliates and the partnerships will be fairly and equitably apportioned according to the respective interests of each.

Partnership funds will not be commingled with those of any other entity.

No loans may be made by the partnership to us or any affiliate.

We or any affiliate, other than other programs sponsored by us or our affiliates, may not purchase the partnerships' producing properties.

Conflict in Establishing Unit Repurchase Price. Under our unit repurchase program (see "Terms of the Offering – Unit Repurchase Program" above for a description of the unit repurchase program), we, once we have received a request from an investor partner that we repurchase that partner's units, will establish a repurchase price. We will determine the repurchase price which will not necessarily represent the fair market value of the units. In setting the price, we will consider our available funds and our desire to acquire production as represented by the units. A conflict will arise in that the price set will be that which we consider to be in our own best interest (to keep the repurchase price as low as possible) and not necessarily in the best interest of the investor partner who is presenting the units for repurchase.

Certain Transactions

As of March 31, 2005, previous limited partnerships sponsored by us have made payments to us or our affiliates as follows:

Name of Partnership	Non-Recurring Management Fee	Sales of Leases	Footage Based Turnkey Drilling and Completion Contracts	Footage and Daywork Drilling Contracts, Services, Chemicals, Supplies and Equipment	Operators Charges	General and Administrative Expense Reimbursement
Pennwest Petroleum Group 1984	$ 61,556	$ 46,250	$ --	$1,824,938	$ 187,119	$ -
Pennwest Petroleum Group 1985-A	58,125	43,400	--	1,829,937	187,334	-
Petrowest Gas Group 1986-A	29,605	22,400	--	873,847	89,624	-
Petrowest Gas Group 1987	35,395	24,850	--	1,062,332	108,718	-
Petrowest Gas Group 1987-B	30,461	21,350	--	913,794	93,514	-
PDC 1987	14,079	715	459,153	--	--	-
PDC 1988	23,842	17,150	--	708,200	72,534	-
PDC 1988-B	6,053	6,450	--	779,587	79,604	-
PDC 1988-C	41,052	26,250	1,361,857	--	--	-
PDC 1989-P	47,171	34,230	--	1,445,275	143,875	-
PDC 1989-A	30,250	57,137	--	1,085,641	--	-
PDC 1989-B	92,750	175,194	3,328,695	--	--	-
PDC 1990-A	5,150	62,209	--	1,265,680	--	-
PDC 1990-B	55,525	72,100	--	2,025,511	--	-
PDC 1990-C	86,950	117,215	--	3,167,563	--	-
PDC 1990-D	92,138	137,225	3,343,524	--	--	-
PDC 1991-A	68,475	75,193	--	2,511,640	--	-
PDC 1991-B	46,587	62,209	--	1,697,764	--	-
PDC 1991-C	68,400	70,235	--	2,513,765	--	-
PDC 1991-D	31,463	153,721	4,812,667	--	--	-
PDC 1992-A	72,717	77,319	--	2,669,888	--	-
PDC 1992-B	74,478	58,829	--	2,754,778	--	-
PDC 1992-C	59,722	149,657	--	5,884,302	--	-
PDC 1993-A	--	101,335	2,840,609	--	--	-
PDC 1993-B	--	80,470	--	2,286,886	--	-
PDC 1993-C	--	96,248	--	2,849,439	--	-
PDC 1993-D	--	94,098	--	2,724,096	--	-
PDC 1993-E	--	272,730	6,930,264	--	--	-
PDC 1994-A	51,387	110,084	--	2,248,204	--	-
PDC 1994-B	67,245	85,240	--	2,921,974	--	-
PDC 1994-C	58,647	63,548	--	2,545,795	--	-
PDC 1994-D	188,719	232,410	8,024,046	--	--	-
PDC 1995-A	36,640	36,389	--	1,566,615	--	-
PDC 1995-B	46,441	59,044	--	1,972,759	--	-
PDC 1995-C	52,862	35,768	--	2,276,962	--	-
PDC 1995-D	203,927	293,036	8,628,760	--	--	-
PDC 1996-A	64,405	109,573	--	2,692,045	--	-
PDC 1996-B	67,118	106,300	--	2,813,259	--	-
PDC 1996-C	98,662	174,509	--	4,117,286	--	-
PDC 1996-D	382,543	565,628	16,075,000	--	--	-
PDC 1997-A	104,174	179,882	--	4,351,672	--	-
PDC 1997-B	168,987	271,709	0	7,079,215	--	-
PDC 1997-C	151,081	257,165	--	6,314,878	--	-
PDC 1997-D	462,989	593,138	19,546,905	--	--	-
PDC 1998-A	131,803	178,267	--	5,555,181	--	-
PDC 1998-B	178,628	228,938	--	7,541,358	--	-
PDC 1998-C	195,320	221,506	--	8,274,895	--	-
PDC 1998-D	513,631	414,444	21,906,777	--	--	-
PDC 1999-A	120,018	173,788	--	5,047,537	--	-
PDC 1999-B	138,497	167,634	--	5,372,762	--	-
PDC 1999-C	177,189	312,633	--	7,408,976	--	-
PDC 1999-D	467,734	849,707	19,550,451	--	--	-
PDC 2000-A	123,918	135,620	--	5,258,900	--	-
PDC 2000-B	290,070	312,974	--	12,307,206	--	--
PDC 2000-C	350,206	392,616	--	14,870,672	--	--
PDC 2000-D	625,000	992,017	26,122,864	--	--	--
PDC 2001-A	234,595	657,134	--	9,955,872	--	--
PDC 2001-B	316,964	392,865	--	13,402,691	--	--
PDC 2001-C	265,681	340,976	--	11,226,780	--	--
PDC 2001-D	610,458	885,361	25,799,097	--	--	--
PDC 2002-A	178,688	212,797	--	7,564,615	--	--

Name of Partnership	Non-Recurring Management Fee	Sales of Leases	Footage Based Turnkey Drilling and Completion Contracts	Footage and Daywork Drilling Contracts, Services, Chemicals, Supplies and Equipment	Operators Charges	General and Administrative Expense Reimbursement
PDC 2002-B	279,511	423,696	---	11,740,764	---	---
PDC 2002-C	235,955	319,536	---	9,945,618	---	---
PDC 2002-D	727,632	906,286	30,962,344	---	---	---
PDC 2003-A	212,076	417,928	---	8,803,018	---	---
PDC 2003-B	433,648	565,506	---	18,000,173	---	---
PDC 2003-C	437,408	466,177	---	18,156,260	---	---
PDC 2003-D	874,921	1,049,386	36,318,571	---	---	---
PDC 2004-A	435,463	777,513	---	30,658,136	---	---
PDC 2004-B	269,981	242,371	---	19,003,112	---	---
PDC 2004-C(1)	269,965	218,468	---	19,001,952	---	---
PDC 2004-D(2)	524,985	518,146	36,952,065	---	---	---
PDC 2005-A(3)	599,062	590,686	---	42,145,013	---	---
PDC 2005-B(4)	606,934	592,167	---	42,118,917	---	---

(1) Partnership funded in August 2004.
(2) Partnership funded in September 2004.
(3) Partnership funded in February 2005.
(4) Partnership funded in April 2005.

FIDUCIARY RESPONSIBILITY OF THE MANAGING GENERAL PARTNER

- The Managing General Partner is accountable to the partnerships as a fiduciary and must exercise good faith respecting the partnerships.

- The limited partnership agreement includes provisions indemnifying the Managing General Partner against liability for losses suffered by the partnership resulting from actions by the Managing General Partner.

We are accountable to the partnerships as a fiduciary and consequently must exercise utmost good faith and integrity in handling partnership affairs. Under West Virginia law, we will owe the investor partners a duty of utmost good faith, fairness, and loyalty. In this regard, we are required to supervise and direct the activities of the partnership prudently and with that degree of care, including acting on an informed basis, which an ordinarily prudent person in a like position would use under similar circumstances. Moreover, we must act at all times in the best interests of the partnership and the investor partners. Since the law in this area is rapidly developing and changing, investors who have questions concerning our responsibilities as Managing General Partner should consult their own counsel. Where the question has arisen, courts have held that a limited partner may institute legal action on behalf of himself and all other similarly situated limited partners (a class action) to recover damages for a breach by a general partner of his fiduciary duty, or on behalf of the partnership (a partnership derivative action) to recover damages from third parties. In addition, limited partners may have the right, subject to procedural and jurisdictional requirements, to bring partnership class actions in federal courts to enforce their rights under the federal securities laws. Further, limited partners who have suffered losses in connection with the purchase or sale of their interests in a partnership may be able to recover such losses from a general partner where the losses result from a violation by the general partner of the antifraud provisions of the federal securities laws. The burden of proving a breach, and all or a portion of the expense of the lawsuit, would have to be borne by the limited partner bringing such action. In the event of a lawsuit for a breach of its fiduciary duty to the partnership and/or the investor partners, we, depending upon the particular circumstances involved, might be able to avail ourselves under West Virginia law of various defenses to the lawsuit, including statute of limitations, estoppels, laches, and doctrines such as the "clean hands" doctrine.

The limited partnership agreement provides for indemnification of the Managing General Partner against liability for losses arising from the action or inaction of the Managing General Partner, if the Managing General Partner, in good faith, determined that the course of conduct was in the best interests of the partnership and the course of conduct did not constitute negligence or misconduct of the Managing General Partner. We may not be indemnified for any liability arising out of a breach of our duty to the partnership or our negligence, fraud, bad faith or misconduct in the performance of our fiduciary duty. The limited partnership agreement provides for indemnification of the Managing General Partner by the partnership for any losses, judgments, liabilities, expenses and amounts paid in settlement of any claims sustained by it in connection with the partnership, provided that the same were not the result of negligence or misconduct on the part of the Managing General Partner. Nevertheless, we shall not be indemnified for liabilities arising under federal and state securities laws unless (1) there has been a successful adjudication on the merits of each count involving securities law violations or (2) the claims have been dismissed with prejudice on the merits by a court of competent jurisdiction or (3) a court of competent jurisdiction approves a settlement of the claims against a particular indemnitee and finds that indemnification of the settlement and the related costs should be made, and the court considering the request for indemnification has been advised of the position of the Securities and Exchange Commission and of the position of any state securities regulatory authority in which securities of the partnership were offered or sold as to indemnification for violations of securities laws; provided, however, the court need only be advised of the positions of the securities regulatory authorities of those states (a) which are specifically set forth in the prospectus and (b) in which plaintiffs claim they were offered or sold partnership units. A successful claim by the Managing General Partner for indemnification would deplete partnership assets by the amount paid. As a result of these indemnification provisions, a purchaser of units may have a more limited right of legal action than he would have if this provision were not included in the limited partnership agreement. To the extent that the indemnification provisions purport to include indemnification for liabilities arising under the Securities Act of 1933, in the opinion of the Securities and Exchange Commission, this indemnification is against public policy as expressed in the Securities Act, and is, therefore, unenforceable.

The limited partnership agreement also provides that the partnership shall not incur the cost of the portion of any insurance which insures any party against any liability as to which the party is prohibited from being indemnified.

PRIOR ACTIVITIES

Prior Partnerships

Petroleum Development Corporation ("PDC"), as general partner, has previously sponsored ten private and fifteen public drilling programs. PDC 2004-2006 Drilling Program is the sixteenth public drilling program sponsored by PDC as general partner. The various drilling programs sponsored by PDC have raised a total of over $665 million.

Each of the previous programs has had as its objective the drilling, completion, and production of oil and natural gas from development wells. The 1984 and 1985 partnerships split investment between shallow oil wells located in Pennsylvania, and gas wells located in the Appalachian Basin. All of the partnerships since and including 1986 were targeted at shallow development gas wells. All funds raised for previous partnerships were spent according to plans as described in the respective private placement memorandum or prospectus. All of the partnerships continue in operation, with monthly cash distributions to investors in all programs continuing. All of the previous programs realized the anticipated tax benefits, and to date the Internal Revenue Service has neither audited any partnership nor challenged any deductions or credits claimed by investors, to the best of the Managing General Partner's knowledge.

For several reasons, including the unpredictability of natural gas and oil development and pricing and differences in property locations, program size, and economic conditions, operating results obtained by these prior partnerships should not be considered as indicative of the operating

results obtainable by the partnerships. You should not assume that you will experience returns, if any, comparable to those experienced by investors in prior programs.

The following table is presented to indicate certain sale characteristics concerning previous gas limited partnerships sponsored by us.

Partnership	Date of Partnership Formation	Date of First Revenue Distribution (1)	Number of Units Sold	Number of Investors	Subscription from Participants	Previous Assessment
Pennwest Petroleum Group 1984	12/84	4/85	32.83	37	$2,462,500	--
Pennwest Petroleum Group 1985-A	11/85	3/86	31.00	35	2,325,000	--
Petrowest Gas Group 1986-A	11/86	4/87	15.00	24	1,125,000	--
Petrowest Gas Group 1987	8/87	1/88	67.25	53	1,345,000	--
Petrowest Gas Group 1987-B	11/87	4/88	57.88	57	1,157,500	--
PDC 1987	12/87	6/88	26.75	20	535,000	--
PDC 1988	7/88	12/88	45.30	43	906,000	--
PDC 1988-B	11/88	4/89	49.50	63	990,000	--
PDC 1988-C	12/88	6/89	78.00	89	1,560,000	--
PDC 1989-P	6/89	12/89	89.63	99	1,792,500	--
PDC 1989-A	10/89	4/90	60.50	110	1,210,000	--
PDC 1989-B	12/89	6/90	185.50	225	3,710,000	--
PDC 1990-A	6/90	11/90	70.30	119	1,406,000	--
PDC 1990-B	9/90	1/91	111.05	153	2,221,000	---
PDC 1990-C	11/90	5/91	173.90	226	3,478,000	--
PDC 1990-D	12/90	6/91	184.28	269	3,685,500	--
PDC 1991-A	3/91	11/91	136.95	208	2,739,000	--
PDC 1991-B	9/91	2/92	93.18	169	1,863,500	--
PDC 1991-C	11/91	4/92	136.80	186	2,736,000	--
PDC 1991-D	12/91	6/92	262.93	432	5,258,500	--
PDC 1992-A	5/92	11/92	145.44	264	2,908,700	--
PDC 1992-B	9/92	1/93	148.96	265	2,979,100	---
PDC 1992-C	11/92	4/93	319.44	532	6,388,900	--
PDC 1993-A	12/92	6/93	151.30	219	3,026,000	--
PDC 1993-B	5/93	11/93	121.75	200	2,435,000	--
PDC 1993-C	9/93	2/94	152.34	232	3,046,700	--
PDC 1993-D	11/93	4/94	145.45	244	2,909,000	--
PDC 1993-E	12/93	7/94	367.94	535	7,358,800	--
PDC 1994-A	5/94	11/94	102.78	176	2,055,500	--
PDC 1994-B	9/94	2/95	134.49	239	2,689,804	--
PDC 1994-C	11/94	4/95	117.29	235	2,345,870	--
PDC 1994-D	12/94	6/95	377.44	529	7,548,761	--
PDC 1995-A	5/95	10/95	73.28	132	1,465,603	--
PDC 1995-B	9/95	1/96	92.88	164	1,857,648	--
PDC 1995-C	11/95	4/96	105.72	170	2,114,496	--
PDC 1995-D	12/95	6/96	407.85	491	8,157,071	--
PDC 1996-A	6/96	11/96	128.81	183	2,576,200	--
PDC 1996-B	9/96	3/97	134.24	223	2,684,707	--
PDC 1996-C	11/96	5/97	197.32	285	3,946,478	--
PDC 1996-D	12/96	6/97	765.09	932	15,301,726	--
PDC 1997-A	5/97	11/97	208.34	312	4,166,946	--
PDC 1997-B	9/97	3/98	337.97	435	6,759,470	--
PDC 1997-C	11/97	5/98	302.16	424	6,043,257	--
PDC 1997-D	12/97	6/98	925.98	1061	18,519,579	--
PDC 1998-A	6/98	12/98	263.61	362	5,272,135	---
PDC 1998-B	9/98	3/99	357.25	371	7,145,101	---
PDC 1998-C	11/98	5/99	390.64	432	7,812,783	---
PDC 1998-D	12/98	7/99	1,026.26	1059	20,525,261	---
PDC 1999-A	5/99	11/99	240.08	223	4,800,739	---
PDC 1999-B	9/99	3/00	278.00	249	5,539,893	---
PDC 1999-C	11/99	5/00	354.38	337	7,087,559	---
PDC 1999-D	12/99	7/00	935.47	857	18,709,342	---
PDC 2000-A	5/00	11/00	247.84	227	4,956,718	---
PDC 2000-B	9/00	3/01	580.14	459	11,602,809	---
PDC 2000-C	11/00	6/01	700.41	563	14,008,256	---
PDC 2000-D	12/00	07/01	1,250.00	1090	25,000,000	---
PDC 2001-A	5/01	11/01	469.19	462	9,383,798	---
PDC 2001-B	9/01	3/02	633.93	619	12,678,577	---

Partnership	Date of Partnership Formation	Date of First Revenue Distribution (1)	Number of Units Sold	Number of Investors	Subscription from Participants	Previous Assessment
PDC 2001-C	11/01	5/02	531.36	595	10,627,234	---
PDC 2001-D	12/01	7/02	1,220.92	1,167	24,418,322	---
PDC 2002-A	4/02	11/02	357.38	384	7,147,522	---
PDC 2002-B	9/02	3/03	559.02	529	11,180,426	---
PDC 2002-C	11/02	5/03	471.91	478	9,438,203	---
PDC 2002-D	12/02	7/03	1,455.26	1,063	29,105,281	---
PDC 2003-A	4/03	11/03	424.65	451	8,483,045	---
PDC 2003-B	9/03	3/04	867.30	801	17,345,901	---
PDC 2003-C	11/03	5/04	874.82	757	17,496,314	---
PDC 2003-D	12/03	7/04	1,749.84	1,235	34,996,823	---
PDC 2004-A	5/04	11/04	1,451.52	1,184	29,030,865	---
PDC 2004-B	7/04	2/05	899.94	675	17,998,735	---
PDC 2004-C	8/04	5/05	899.88	673	17,997,637	---
PDC 2004-D	9/04	(2)	1,749.95	1,110	34,999,027	---
PDC 2005-A	2/05	(3)	1,996.87	1,527	39,937,470	--
PDC 2005-B	4/05	(4)	2,023.11	1,646	40,462,267	--

(1) Cash distribution made each month since date of first distribution.

(2) Partnership closed on September 9, 2004. Wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.

(3) Partnership closed on February 9, 2005. Wells were drilled in the second and third quarters of 2005; first revenue distribution to commence in fall of 2005.

(4) Partnership closed on April 30, 2005. Wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in winter of 2005/2006.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Capital and Expenditures of Prior Partnerships

The following table provides information regarding the capital raised and expended by previous limited partnerships sponsored by us and our affiliates as of March 31, 2005. The information presented in the following table has been prepared in conformity with generally accepted accounting principles.

Partnership	**Cash Contribution By Managing General Partner**	**Total Partnership Revenues Allocated**	**Total Expenditures, Net of Operating Costs, Direct Costs & Administrative Costs**	**Total Operating Costs**	**Total Direct Costs**	**Total Administrative Costs**
Pennwest Petroleum Group 1984	$129,605	$2,757,814	$2,592,105	$ 1,006,669	$24,491	$ -
Pennwest Petroleum Group 1985-A	122,368	2,648,111	2,447,368	1,158,697	24,865	-
Petrowest Gas Group 1986-A	59,210	1,519,414	1,184,210	638,835	8,617	-
Petrowest Gas Group 1987	70,789	2,215,120	1,415,789	861,579	2,724	-

Petrowest Gas Group 1987-B	60,921	1,115,963	1,218,421	463,320	18,478	-
PDC 1987	28,158	746,703	563,158	269,184	17,529	-
PDC 1988	47,684	1,601,642	953,684	548,556	23,184	-
PDC 1988-B	52,105	897,595	1,042,105	497,751	1,464	-
PDC 1988-C	82,105	1,763,259	1,642,105	810,772	20,018	-
PDC -1989-P	94,342	2,614,782	1,886,842	915,184	22,558	-
PDC 1989-A	114,278	2,264,865	1,324,278	766,955	78,753	-
PDC 1989-B	350,389	4,232,510	4,060,389	1,627,218	123,844	-
PDC 1990-A	132,789	1,149,693	1,538,789	497,682	67,134	-
PDC 1990-B	209,761	2,558,848	2,430,761	1,016,937	86,258	-
PDC 1990-C	328,478	4,482,966	3,806,478	1,751,685	126,938	-
PDC 1990-D	348,075	3,837,315	4,033,575	1,525,439	130,033	-
PDC 1991-A	258,683	3,374,197	2,997,683	1,264,763	120,704	-
PDC 1991-B	175,997	1,982,350	2,039,497	665,771	94,433	-
PDC 1991-C	258,400	3,173,363	2,994,400	1,144,139	110,444	-
PDC 1991-D	496,639	4,829,641	5,755,139	1,942,869	166,385	-
PDC 1992-A	274,711	1,529,475	3,183,411	724,455	81,039	-
PDC 1992-B	281,361	3,896,399	3,260,461	1,293,311	109,698	-
PDC 1992-C	603,396	9,651,342	6,992,296	3,021,583	164,430	-
PDC 1993-A	294,194	6,063,653	3,320,194	1,772,042	99,040	-
PDC 1993-B	236,736	2,519,774	2,671,736	843,607	97,746	-
PDC 1993-C	296,207	2,586,200	3,342,907	1,064,410	113,714	-
PDC 1993-D	282,819	2,700,072	3,191,819	894,608	108,290	-
PDC 1993-E	715,438	6,660,198	8,074,238	1,723,886	159,836	-
PDC 1994-A	449,641	1,696,778	2,505,141	717,767	73,180	-
PDC 1994-B	588,395	2,714,646	3,278,199	834,350	86,732	-
PDC 1994-C	513,159	2,135,683	2,859,029	700,489	85,296	-
PDC 1994-D	1,651,292	6,876,463	9,200,053	2,167,834	153,944	-
PDC 1995-A	320,601	1,430,500	1,786,204	499,302	63,836	-
PDC 1995-B	406,361	1,095,171	2,264,009	349,654	72,295	-
PDC 1995-C	462,546	1,425,578	2,577,042	636,229	74,065	-
PDC 1995-D	1,784,359	6,228,153	9,941,430	2,126,424	150,292	-
PDC 1996-A	560,324	2,962,597	3,136,524	803,843	65,520	-
PDC 1996-B	583,924	2,639,617	3,268,631	771,345	68,702	-
PDC 1996-C	858,359	2,910,146	4,822,837	959,363	82,358	-
PDC 1996-D	3,328,126	11,132,374	18,629,852	3,891,432	163,467	-
PDC 1997-A	906,311	2,717,376	5,073,257	803,663	69,786	-
PDC 1997-B	1,470,185	3,524,767	8,229,655	1,290,694	87,267	-
PDC 1997-C	1,314,409	5,279,364	7,357,666	1,587,820	87,387	-
PDC 1997-D	4,028,009	10,538,631	22,547,588	4,623,791	170,671	-
PDC 1998-A	1,146,690	4,844,972	6,418,825	1,572,561	63,394	-
PDC 1998-B	1,554,059	7,165,499	8,699,160	2,199,632	69,227	-
PDC 1998-C	1,699,280	7,503,018	9,512,063	2,682,622	73,175	-
PDC 1998-D	4,464,244	14,071,307	24,989,505	4,512,799	139,213	-
PDC 1999-A	1,044,161	5,361,890	5,844,900	1,429,208	48,688	-
PDC 1999-B	1,204,927	7,202,010	6,744,820	1,879,523	54,956	-
PDC 1999-C	1,541,544	6,746,910	8,629,103	1,764,531	61,065	-
PDC 1999-D	4,069,282	17,603,791	22,778,624	3,987,846	125,277	-
PDC 2000-A	1,078,086	4,694,137	6,034,804	1,006,260	39,714	-
PDC 2000-B	2,523,611	8,321,096	14,126,420	2,182,090	54,592	-
PDC 2000-C	3,046,796	8,218,364	17,055,052	2,584,106	60,444	-
PDC 2000-D	5,437,500	14,980,509	30,437,500	3,949,568	115,794	-
PDC 2001-A	2,040,976	5,566,356	11,424,774	1,407,796	44,510	-

PDC 2001-B	2,757,591	6,760,733	15,436,168	1,866,502	52,736	-
PDC 2001-C	2,311,423	5,771,151	12,938,657	1,757,381	49,015	-
PDC 2001-D	5,310,985	13,129,794	29,729,307	3,213,872	92,341	-
PDC 2002-A	1,554,586	5,408,342	8,702,108	1,472,253	27,815	70,373
PDC 2002-B	2,431,743	6,047,257	13,612,169	1,513,952	33,104	110,066
PDC 2002-C	2,052,809	5,594,082	11,491,012	1,341,304	38,146	92,935
PDC 2002-D	6,330,399	12,192,197	35,435,680	2,996,360	73,750	286,530
PDC 2003-A	1,845,062	5,165,668	10,328,107	888,064	24,372	86,703
PDC 2003-B	3,772,733	8,422,054	21,118,634	1,279,102	33,874	177,165
PDC 2003-C	3,805,448	6,678,274	21,301,762	1,081,830	30,372	178,445
PDC 2003-D	7,611,809	11,906,793	42,608,632	2,049,188	43,099	357,530
PDC 2004-A	6,419,029	10,138,223	5,449,894	1,329,580	26,894	240,235
PDC 2004-B	3,979,709	2,967,462	21,978,444	383,232	16,624	148,875
PDC 2004-C(1)	3,979,466	-	21,977,103	-	-	148,875
PDC 2004-D(2)	7,738,652	-	42,737,679	-	-	289,557
PDC 2005-A(3)	8,826,181	-	48,763,651	-	-	-
PDC 2005-B(4)	8,942,161	-	49,404,428	-	-	-

(1) Partnership closed on August 12, 2004. Wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution commenced in May 2005.

Partnership closed on September 9, 2004. Wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.

Partnership closed on February 9, 2005. Wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in fall of 2005.

Partnership closed on April 30, 2005. Wells will be drilled in the second and third quarter of 2005; first revenue distribution to commence in winter of 2005/2006.

Previous Drilling Activities

The following table reflects the drilling activity of previous limited partnerships sponsored by us as of March 31, 2005. All of the wells drilled were development wells, except as otherwise noted.

Productive Well Table
March 31, 2005

	Gross Wells(1)			Net Wells(2)		
Partnership	Oil	Gas	Dry	Oil	Gas	Dry
Pennwest Petroleum Group 1984	27	13	-	27	5.5	-
Pennwest Petroleum Group 1985-A	14	13	1	14	7.8	.6
Petrowest Gas Group 1986-A		8	2	-	5.4	1.0
Petrowest Gas Group 1987	-	9	1(3)	-	7.1	.1(3)
Petrowest Gas Group	-	9	1	-	5.5	.6
PDC 1987	-	7	-	-	2.6	-
PDC 1988	-	5	1	-	4.1	.8
PDC 1988-B	-	5	-	-	4.7	-
PDC 1988-C	-	9	1	-	7.0	.8
PDC 1989-P	-	8	1	-	7.8	.9
PDC 1989-A	-	6	1	-	5.5	.9
PDC 1989-B	-	19	2	-	17.0	1.8
PDC 1990-A	-	7	1	-	6.0	.9
PDC 1990-B	-	11	-	-	10.3	-
PDC 1990-C	-	15	2	-	14.4	2.0
PDC 1990-D	-	16	1	-	15.8	1.0

PDC 1991-A	-	13	-	-	12.0	-
PDC 1991-B	-	8	2	-	7.2	2.0
PDC 1991-C	-	12	2	-	11.2	1.5
PDC 1991-D	-	21	5	-	20.4	4.4
PDC 1992-A	-	12	2	-	11.0	2.0
PDC 1992-B	-	14	1	-	12.3	.5
PDC 1992-C	-	26	3	-	24.8	2.5
PDC 1993-A	-	16	1	-	14.7	1.0
PDC 1993-B	-	11	4	-	10.8	4.0
PDC 1993-C	-	15	2	-	13.8	2.0
PDC 1993-D	-	13	2	-	12.1	2.0
PDC 1993-E	-	34	2	-	33.3	2.0
PDC 1994-A	-	9	1	-	8.9	1.0
PDC 1994-B	-	13	1	-	12.4	1.0
PDC 1994-C	-	12	1	-	11.1	1.0
PDC 1994-D	-	39	4	-	35.4	4.0
PDC 1995-A	-	8	1	-	7.1	1.0
PDC 1995-B	-	8	3	-	7.1	3.0
PDC 1995-C	-	12	1	-	9.6	1.0
PDC 1995-D	-	42	2	-	37.5	2.0
PDC 1996-A	-	14	2	-	11.5	2.0
PDC 1996-B	-	15	-	-	13.2	-
PDC 1996-C	-	22	2	-	17.6	1.9
PDC 1996-D	-	80(4)	5	-	62.3	4.3
PDC 1997-A	-	21(5)	1	-	11.1	0.1
PDC 1997-B	-	34(6)	2	-	23.4	2.0
PDC 1997-C	-	28	2	-	19.5	1.1
PDC 1997-D	-	94	7	-	72.7	4.5
PDC 1998-A	-	29	2	-	19.2	2.0
PDC 1998-B	-	41	2	-	26.9	1.9
PDC 1998-C	-	37	1	-	29.9	1.0
PDC 1998-D	-	89(7)	8(8)	-	70.8(7)	7.6(8)
PDC 1999-A	-	24	-	-	19.5	-
PDC 1999-B	-	26	1	-	21.0	0.5
PDC 1999-C	-	24	2	-	20.9	2.0
PDC 1999-D	-	51	-	-	37.5	-
PDC 2000-A	-	14	-	-	10.5	-
PDC 2000-B	-	25	2	-	18.0	2.0
PDC 2000-C	-	31	-	-	22.1	-
PDC 2000-D	-	41	2	-	32.0	1.4
PDC 2001-A	-	32	-	-	15.4	-
PDC 2001-B	-	18	1	-	15.9	.9
PDC 2001-C	-	18	1	-	15.5	.9
PDC 2001-D	-	33	-	-	29.1	-
PDC 2002-A	-	10	-	-	7.7	-
PDC 2002-B	-	14	-	-	12.8	-
PDC 2002-C	-	14	-	-	12.7	-
PDC 2002-D	-	36	-	-	32.3	-
PDC 2003-A	-	25	-	-	11.5	-
PDC 2003-B	-	26	-	-	23.2	-
PDC 2003-C	-	25	-	-	23.25	-
PDC 2003-D	-	41	2	-	40.0	1.55
PDC 2004-A	-	37	-	-	32.5	-
PDC 2004-B	-	23	-	-	21.0	-
PDC 2004-C	-	20	2	-	19.0	1.43
PDC 2004-D(9)	-	44	-	-	42.78	-
PDC 2005-A(10)	-	10	-	-	9.88	-
PDC 2005-B(11)	-	-	-	-	-	-
Total	41	1,664	102	41	1,363.31	88.38

(1) Gross wells include all wells in which the partnerships owned a Working Interest.

(2) Net wells are the number of gross wells multiplied by the percentage Working Interest owned by the partnerships in the gross wells.

(3) The dry hole indicated represents an exploratory well.

(4) Ten wells in the Angel Antrim Shale Project were productive wells and subsequently plugged in third quarter of 2000.

(5) Three wells in the Angel Antrim Shale Project were productive wells and subsequently plugged in the third quarter of 2000.

(6) Six wells in the East 23 Antrim Shale Project were productive wells and subsequently plugged in the third quarter of 2000.
(7) One of the gas wells represents an exploratory well with a net interest of .9.
(8) Three of the dry holes represent exploratory wells with a net interest of 2.7.
(9) Partnership funded September 2004. Wells were drilled in the fourth quarter of 2004 and the first quarter of 2005.
Partnership funded February 2005. Wells will be drilled in the second and third quarters of 2005.
Partnership funded April 2005. Wells will be drilled in the second and third quarters of 2005.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Payout and Net Cash Tables

The following tables provide information concerning the operating results of previous limited partnerships sponsored by us as of March 31, 2005. The information presented in the following tables has been prepared in conformity with generally accepted accounting principles.

Participants' Payout Table
March 31, 2005

			Revenues Before Deducting Operating Costs(3)	
Partnership	Investors' Funds Invested (1)	Total Expenditures Including Operating Costs (2)	Total As of March 31, 2005	During Three Months Ended March 31, 2005
Pennwest Petroleum Group 1984	$2,093,155	$3,447,149	$2,436,707	$20,755
Pennwest Petroleum Group 1985-A	1,976,250	3,451,531	2,323,903	70,728
Petrowest Gas Group 1986-A	956,250	1,740,145	1,307,432	27,042
Petrowest Gas Group 1987	1,143,250	2,152,422	1,914,460	28,763
Petrowest Gas Group 1987-B	983,875	1,609,528	964,269	13,044
PDC 1987	454,750	803,607	644,474	7,189
PDC 1988	770,100	1,441,982	1,376,116	46,031
PDC 1988-B	841,500	1,458,949	769,327	14,438
PDC 1988-C	1,326,000	2,337,057	1,518,412	30,691
PDC -1989-P	1,523,625	2,667,486	2,256,396	42,222
PDC 1989-A	1,028,500	1,875,926	1,813,669	34,190
PDC 1989-B	3,153,500	5,107,981	3,405,155	64,714
PDC 1990-A	1,195,100	1,861,731	930,420	21,235
PDC 1990-B	1,887,850	3,093,412	2,055,127	42,666
PDC 1990-C	2,956,300	4,952,985	3,614,229	118,263
PDC 1990-D	3,132,674	5,009,637	3,114,476	73,933
PDC 1991-A	2,328,150	3,842,952	2,711,215	49,696
PDC 1991-B	1,583,975	2,470,387	1,593,864	40,114
PDC 1991-C	2,325,600	3,729,305	2,550,303	63,705
PDC 1991-D	4,469,725	6,925,867	3,901,021	142,797
PDC 1992-A	2,472,396	3,692,655	1,443,932	35,775
PDC 1992-B	2,532,246	4,080,945	3,125,455	88,006
PDC 1992-C	5,430,563	8,896,856	7,777,184	202,318
PDC 1993-A	2,647,750	4,550,863	4,979,318	88,514
PDC 1993-B	2,130,620	3,184,903	2,072,673	72,465
PDC 1993-C	2,665,865	4,009,531	2,155,281	60,963
PDC 1993-D	2,545,375	3,721,145	2,240,027	69,989

PDC 1993-E	6,438,950	8,873,481	5,512,118	177,291
PDC 1994-A	1,798,563	2,679,782	1,365,243	29,002
PDC 1994-B	2,353,579	3,405,672	2,179,063	46,207
PDC 1994-C	2,052,636	2,956,218	1,710,735	40,072
PDC 1994-D	6,605,166	9,349,276	5,523,211	132,833
PDC 1995-A	1,282,403	1,910,689	1,149,998	30,082
PDC 1995-B	1,625,442	2,193,429	884,475	22,989
PDC 1995-C	1,850,184	2,679,813	1,148,300	34,926
PDC 1995-D	7,137,437	9,934,984	5,020,873	148,102
PDC 1996-A	2,241,294	3,164,365	2,370,078	47,859
PDC 1996-B	2,335,695	3,227,152	2,111,693	76,254
PDC 1996-C	3,433,436	4,643,339	2,328,117	75,886
PDC 1996-D	13,312,502	17,788,934	8,905,899	324,235
PDC 1997-A	3,625,243	4,682,252	2,173,901	70,412
PDC 1997-B	5,880,739	7,620,288	2,819,815	111,885
PDC 1997-C	5,257,634	7,020,660	4,223,491	160,448
PDC 1997-D	16,112,034	21,731,011	8,430,905	371,265
PDC 1998-A	4,586,758	6,410,845	3,875,977	195,914
PDC 1998-B	6,216,237	8,828,626	5,732,400	297,462
PDC 1998-C	6,797,121	9,749,269	6,002,415	334,687
PDC 1998-D	17,856,977	23,648,622	11,257,046	667,802
PDC 1999-A	4,176,643	5,862,264	4,289,511	249,411
PDC 1999-B	4,819,707	6,918,794	5,761,608	336,168
PDC 1999-C	6,166,176	8,407,294	5,397,529	273,153
PDC 1999-D	16,277,127	21,636,080	14,083,033	691,266
PDC 2000-A	4,312,345	5,715,126	3,755,310	139,943
PDC 2000-B	10,194,444	13,202,278	6,656,876	341,740
PDC 2000-C	12,187,183	15,896,025	6,574,690	418,422
PDC 2000-D	21,750,000	27,797,161	11,984,408	661,066
PDC 2001-A	8,163,904	10,375,048	4,453,085	249,920
PDC 2001-B	11,030,362	13,914,846	5,408,587	278,568
PDC 2001-C	9,245,693	11,812,328	4,616,921	254,320
PDC 2001-D	21,243,940	26,383,786	10,503,834	727,418
PDC 2002-A	6,218,344	8,038,703	4,326,674	298,049
PDC 2002-B	9,726,970	12,096,634	4,837,805	411,977
PDC 2002-C	8,211,237	10,221,829	4,475,266	328,570
PDC 2002-D	25,321,594	31,071,210	9,753,758	865,121
PDC 2003-A	7,388,949	9,128,920	4,132,534	468,762
PDC 2003-B	15,090,933	18,396,278	6,737,643	1,026,230
PDC 2003-C	15,221,793	18,386,073	5,342,619	984,457
PDC 2003-D	30,447,236	36,670,649	9,525,434	2,540,231
PDC 2004-A	25,546,830	30,116,042	8,110,578	3,585,930
PDC 2004-B	15,918,838	18,318,620	2,373,970	957,537
PDC 2004-C(4)	15,917,866	17,997,637	-	-
PDC 2004-D(5)	30,954,610	34,999,027	-	-
PDC 2005-A(6)	35,304,723	39,937,470	-	-
PDC 2005-B(7)	35,768,644	40,462,267	-	-

Total Subscriptions, less commissions, management fee, and offering costs.
Includes the total of the subscriptions, assessments, funds advanced by the Managing General Partner to the general or limited partnerships, inclusive of operating costs. None of the partnerships has borrowed any fu
Represents the accrued gross revenues credited to the participants from oil and gas revenues net royalties to landowners, overriding royalty interest, and other burdens, excluding interest income.

Partnership funded in August 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution commenced in May 2005.
Partnership funded in September 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.
Partnership funded in February 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in the fall of 2005.
Partnership funded in April 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in the winter of 2005/2006.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Participants' Net Cash Table
March 31, 2005

			Total Revenues After Deducting Operating Costs(3)		Cash Distributions(4)		
	Investors' Funds Invested	Total Expenditures Net of Operating Costs(2)	Total As of March 31, 2005	Three Months Ended March 31, 2005	Total As of March 13, 2005	Three Months Ended March 31, 2005	Aggregate Section 29 Tax Credits(5)
Pennwest Petroleum Group 1984	$2,093,125	$2,462,500	$1,452,058	$ 8,705	$1,382,556	$ 8,705	$ 571,757
Pennwest Petroleum Group 1985-A	1,976,250	2,325,000	1,197,372	24,383	1,154,100	24,383	716,864
Petrowest Gas Group 1986-A	956,250	1,125,000	692,287	16,658	665,517	16,658	505,102
Petrowest Gas Group 1987	1,143,250	1,345,000	1,107,037	16,718	1,064,417	16,718	579,823
Petrowest Gas Group 1987-B	983,875	1,157,500	512,242	7,678	485,872	7,678	392,383
PDC 1987	454,750	535,000	375,868	3,356	358,296	3,356	251,862
PDC 1988	770,100	906,000	840,135	11,776	803,246	11,776	509,430
PDC 1988-B	841,500	990,000	300,378	2,292	276,538	2,292	286,312
PDC 1988-C	1,326,000	1,560,000	741,356	17,138	698,300	17,138	552,091
PDC 1989-P	1,523,625	1,792,500	1,381,410	25,156	1,303,525	25,156	907,101
PDC 1989-A	1,028,500	1,210,000	1,147,744	23,000	1,104,660	23,000	278,048
PDC 1989-B	3,153,500	3,710,000	2,007,174	38,315	1,901,538	38,315	1,780,305
PDC 1990-A	1,195,100	1,406,000	474,689	8,176	414,476	8,176	161,679
PDC 1990-B	1,887,850	2,221,000	1,182,715	25,113	1,144,955	25,113	698,164
PDC 1990-C	2,956,300	3,478,000	2,139,244	81,179	2,070,006	81,179	765,656
PDC 1990-D	3,132,674	3,685,500	1,790,339	44,214	1,729,472	44,214	933,900
PDC 1991-A	2,328,150	2,739,000	1,607,264	11,740	1,503,799	11,740	951,026
PDC 1991-B	1,583,975	1,863,500	986,977	26,564	958,102	26,564	556,159
PDC 1991-C	2,325,600	2,736,000	1,556,998	22,398	1,470,398	22,398	868,393
PDC 1991-D	4,469,725	5,258,500	2,233,654	77,565	2,160,642	77,565	1,152,905
PDC 1992-A	2,472,396	2,908,700	659,977	20,277	581,253	20,277	445,185
PDC 1992-B	2,532,246	2,979,100	2,023,610	50,508	1,962,553	50,508	1,045,436
PDC 1992-C	5,430,563	6,388,900	5,269,228	121,724	5,147,114	121,724	2,093,099
PDC 1993-A	2,647,750	3,026,000	3,454,455	55,948	3,260,279	55,948	149,551
PDC 1993-B	2,130,620	2,435,000	1,322,770	51,747	1,263,863	51,747	-
PDC 1993-C	2,665,865	3,046,700	1,192,450	36,341	1,136,064	36,341	-
PDC 1993-D	2,545,375	2,909,000	1,427,882	45,407	1,386,644	45,407	-
PDC 1993-E	6,438,950	7,358,800	3,997,437	90,381	3,848,489	90,381	-
PDC 1994-A	1,798,563	2,055,500	740,961	21,778	700,991	21,778	-
PDC 1994-B	2,353,579	2,689,804	1,463,195	32,432	1,407,937	32,432	-
PDC 1994-C	2,052,636	2,345,870	1,100,387	27,716	1,043,950	27,716	-
PDC 1994-D	6,605,166	7,548,761	3,722,696	90,891	3,535,841	90,891	-
PDC 1995-A	1,282,403	1,465,603	704,912	18,082	656,853	18,082	-
PDC 1995-B	1,625,442	1,857,648	548,694	14,448	492,686	14,448	-
PDC 1995-C	1,850,184	2,114,496	582,983	14,817	526,186	14,817	-
PDC 1995-D	7,137,437	8,157,071	3,242,960	92,832	3,032,264	92,832	-
PDC 1996-A	2,241,294	2,576,200	1,781,913	31,534	1,647,095	31,534	-

	Investors' Funds Invested	Total Expenditures Net of Operating Costs(2)	Total Revenues After Deducting Operating Costs(3): Total As of March 31, 2005	Total Revenues After Deducting Operating Costs(3): Three Months Ended March 31, 2005	Cash Distributions(4): Total As of March 13, 2005	Cash Distributions(4): Three Months Ended March 31, 2005	Aggregate Section 29 Tax Credits(5)
PDC 1996-B	2,335,695	2,684,707	1,569,248	75,909	1,444,332	75,909	-
PDC 1996-C	3,433,436	3,946,478	1,649,256	48,977	1,531,981	48,977	-
PDC 1996-D	13,312,502	15,301,726	6,418,691	212,317	6,060,601	212,317	-
PDC 1997-A	3,625,243	4,166,946	1,658,595	43,731	1,564,674	43,731	-
PDC 1997-B	5,880,739	6,759,470	1,958,997	99,894	1,809,596	99,894	-
PDC 1997-C	5,257,634	6,043,257	3,246,088	112,443	2,924,177	112,443	-
PDC 1997-D	16,112,034	18,519,579	5,219,473	240,662	4,835,588	240,662	-
PDC 1998-A	4,586,758	5,272,135	2,737,268	163,929	2,586,241	163,929	-
PDC 1998-B	6,216,237	7,145,101	4,048,875	233,016	3,955,477	233,016	-
PDC 1998-C	6,797,121	7,812,783	4,065,929	271,630	3,800,272	271,630	-
PDC 1998-D	17,856,977	20,525,261	8,133,685	579,855	7,672,121	579,855	-
PDC 1999-A	4,176,643	4,800,739	3,227,987	197,001	3,088,398	197,001	-
PDC 1999-B	4,819,707	5,539,893	4,382,708	269,799	4,195,504	269,799	-
PDC 1999-C	6,166,176	7,087,559	4,077,794	210,546	3,836,472	210,546	-
PDC 1999-D	16,277,127	18,709,342	11,156,296	528,692	10,968,993	528,692	-
PDC 2000-A	4,312,345	4,956,718	2,996,902	96,990	2,711,095	96,990	-
PDC 2000-B	10,094,444	11,602,809	5,057,407	253,298	4,638,697	253,298	-
PDC 2000-C	12,187,183	14,008,256	4,686,922	299,242	4,471,399	299,242	-
PDC 2000-D	21,750,000	25,000,000	9,187,247	502,276	8,455,308	502,276	-
PDC 2001-A	8,163,904	9,383,798	3,461,835	185,386	2,940,277	185,386	-
PDC 2001-B	11,030,362	12,678,577	4,172,318	192,957	3,846,120	192,957	-
PDC 2001-C	9,245,693	10,627,234	3,431,826	177,020	3,053,699	177,020	-
PDC 2001-D	21,243,940	24,418,322	8,538,370	559,430	7,568,764	559,430	-
PDC 2002-A	6,218,344	7,147,522	3,435,493	174,529	2,936,495	174,529	-
PDC 2002-B	9,726,970	11,180,426	3,921,598	303,933	3,488,892	303,933	-
PDC 2002-C	8,211,237	9,438,203	3,691,640	251,713	3,148,241	251,713	-
PDC 2002-D	25,321,594	29,105,281	7,787,828	645,016	6,535,990	645,016	-
PDC 2003-A	7,388,949	8,483,045	3,486,659	391,293	2,824,482	391,293	-
PDC 2003-B	15,090,933	17,345,901	5,687,266	857,166	4,943,995	857,166	-
PDC 2003-C	15,221,793	17,496,314	4,452,860	810,809	3,859,556	810,809	-
PDC 2003-D	30,447,236	34,996,823	7,851,608	2,060,875	6,420,112	2,060,875	-
PDC 2004-A	25,676,116	29,030,865	7,025,401	3,121,578	4,587,985	3,121,578	-
PDC 2004-B	15,918,838	17,998,735	2,054,085	834,178	834,178	834,178	-
PDC 2004-C(6)	15,917,866	17,997,637	-	-	-	-	-
PDC 2004-D(7)	30,954,610	34,999,027	-	-	-	-	-
PDC 2005-A(8)	35,304,723	39,937,470	-	-	-	-	-
PDC 2005-B(9)	35,768,644	40,462,267	-	-	-	-	-

(1) Total Subscriptions, less commissions, management fee, and offering costs.

(2) Includes the total of the subscriptions, assessments, funds advanced by the Managing General Partner to the general or limited partnerships, exclusive of operating costs. None of the partnerships has borrowed any funds.

(3) Represents the accrued gross revenues credited from oil and gas production, excluding operating costs, landowners' royalty interests, overriding royalty interests, and other burdens.

(4) Represents the net cash distributed to the partnerships. All cash distributions to the partners were made from operations and constituted ordinary income.

(5) Wells drilled after December 31, 1992 do not qualify for the credit.

(6) Partnership funded in August 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution commenced in May 2005.

(7) Partnership funded in September 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.

(8) Partnership funded in February 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in fall 2005.

(9) Partnership funded in April 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in winter 2005/2006.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Managing General Partner's Payout Table
March 31, 2005

Partnership	Total Expenditures Including Operating Costs(1)	Revenues Before Deducting Operating Costs(2) Total As of March 31, 2005	Revenues Before Deducting Operating Costs(2) During Three Months Ended March 31, 2005
Pennwest Petroleum Group 1984	$176,116	$321,107	$3,394
Pennwest Petroleum Group	179,398	324,209	11,527
Petrowest Gas Group 1986-A	101,517	211,982	4,581
Petrowest Gas Group 1987	127,669	300,660	4,772
Petrowest Gas Group 1987-B	90,691	151,693	2,175
PDC 1987	46,264	102,229	1,214
PDC 1988	83,442	225,525	7,707
PDC 1988-B	82,371	128,268	2,479
PDC 1988-C	135,838	244,847	5,144
PDC-1989-P	157,098	358,386	7,025
PDC 1989-A	294,061	451,196	8,547
PDC 1989-B	703,470	827,355	16,179
PDC 1990-A	241,874	219,273	5,309
PDC 1990-B	440,544	503,721	10,667
PDC 1990-C	732,116	868,737	29,566
PDC 1990-D	679,410	722,839	18,483
PDC 1991-A	540,199	662,982	12,424
PDC 1991-B	329,314	388,486	10,029
PDC 1991-C	519,678	623,060	15,926
PDC 1991-D	938,526	928,620	35,699
PDC 1992-A	296,250	85,543	-
PDC 1992-B	582,525	770,944	22,002
PDC 1992-C	1,281,453	1,874,158	50,579
PDC 1993-A	640,413	1,084,335	19,430
PDC 1993-B	428,186	447,101	15,907
PDC 1993-C	511,500	430,919	13,382
PDC 1993-D	473,572	460,045	15,363
PDC 1993-E	1,084,479	1,148,080	38,918
PDC 1994-A	616,306	331,535	7,250
PDC 1994-B	793,609	535,583	11,552
PDC 1994-C	688,596	424,948	10,018
PDC 1994-D	2,172,555	1,353,252	33,207
PDC 1995-A	438,653	280,502	7,520
PDC 1995-B	492,529	210,696	5,747
PDC 1995-C	607,523	277,278	8,731
PDC 1995-D	2,283,162	1,207,280	37,024
PDC 1996-A	841,522	592,519	11,965
PDC 1996-B	881,526	527,924	19,063
PDC 1996-C	1,221,219	582,029	18,971
PDC 1996-D	4,895,817	2,226,475	81,059
PDC 1997-A	1,264,454	543,475	17,603
PDC 1997-B	1,987,328	704,952	27,971
PDC 1997-C	2,012,212	1,055,873	40,112
PDC 1997-D	5,611,039	2,107,726	92,816
PDC 1998-A	1,643,936	968,995	48,979
PDC 1998-B	2,139,393	1,433,099	74,366
PDC 1998-C	2,518,591	1,500,603	83,672
PDC 1998-D	5,992,895	2,814,261	166,950
PDC 1999-A	1,460,533	1,072,379	62,353
PDC 1999-B	1,760,506	1,440,402	84,042

Partnership	Total Expenditures Including Operating Costs(1)	Revenues Before Deducting Operating Costs(2): Total As of March 31, 2005	Revenues Before Deducting Operating Costs(2): During Three Months Ended March 31, 2005
PDC 1999-C	2,047,405	1,349,381	68,288
PDC 1999-D	5,255,668	3,520,758	172,817
PDC 2000-A	1,365,652	938,827	34,986
PDC 2000-B	3,160,824	1,664,220	85,435
PDC 2000-C	3,803,578	1,643,674	104,606
PDC 2000-D	6,705,701	2,996,101	165,266
PDC 2001-A	2,502,032	1,113,271	62,480
PDC 2001-B	3,440,560	1,352,146	69,642
PDC 2001-C	2,932,724	1,154,230	63,580
PDC 2001-D	6,651,734	2,625,960	181,855
PDC 2002-A	2,163,473	1,081,668	74,512
PDC 2002-B	3,062,592	1,209,452	102,994
PDC 2002-C	2,648,633	1,118,816	82,143
PDC 2002-D	7,434,579	2,438,439	216,280
PDC 2003-A	2,111,623	1,033,134	117,190
PDC 2003-B	4,035,332	1,684,411	256,558
PDC 2003-C	4,027,891	1,335,655	246,114
PDC 2003-D	8,030,270	2,381,359	635,058
PDC 2004-A	6,690,326	2,027,645	896,482
PDC 2004-B	4,059,680	593,492	239,384
PDC 2004-C(3)	3,979,466	-	-
PDC 2004-D(4)	7,738,652	-	-
PDC 2005-A(5)	8,826,181	-	-
PDC 2005-B(6)	8,942,161	-	-

(1) Includes Managing General Partner share of drilling costs.
(2) Represents the accrued gross revenues credited to the managing general partner(s).
(3) Partnership funded in August 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution commenced in May 2005.
(4) Partnership funded in September 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.
(5) Partnership funded in February 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in fall 2005.
(6) Partnership funded in April 2005; wells will be drilled in second and third quarters of 2005; first revenue distribution to commence in winter 2005/2006.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Managing General Partner's Net Cash Table
March 31, 2005

Partnership	Total Expenditures Net of Operating Costs	Total Revenues After Deducting Operating Costs(2): Total as of March 31, 2005	Total Revenues After Deducting Operating Costs(2): Three Months Ended March 31, 2005	Cash Distributions(3): Total as of March 31, 2005	Cash Distributions(3): Three Months Ended March 31, 2005	Aggregate Section 29 Tax Credits(4)
Pennwest Petroleum Group 1984	$ 129,605	$274,596	$3,077	$273,392	$3,077	$ 30,092
Pennwest Petroleum Group 1985-A	122,368	267,178	10,307	270,565	10,307	37,730
Petrowest Gas Group 1986-A	59,210	169,675	4,034	168,913	4,034	26,584
Petrowest Gas Group 1987	70,789	243,780	4,137	242,733	4,137	30,517
Petrowest Gas Group 1987-B	60,921	121,923	1,892	119,473	1,892	20,652
PDC 1987	28,158	84,123	1,011	82,775	1,011	13,256
PDC 1988	47,684	189,768	5,903	186,912	5,903	26,812

Partnership	Total Expenditures Net of Operating Costs	Total Revenues After Deducting Operating Costs(2) Total as of March 31, 2005	Three Months Ended March 31, 2005	Cash Distributions(3) Total as of March 31, 2005	Three Months Ended March 31, 2005	Aggregate Section 29 Tax Credits(4)
PDC 1988-B	52,105	98,002	1,839	94,765	1,839	15,069
PDC 1988-C	82,105	191,114	4,430	187,154	4,430	29,057
PDC 1989-P	94,342	295,630	6,126	288,255	6,126	47,742
PDC 1989-A	114,278	271,413	5,749	277,392	5,749	69,512
PDC 1989-B	350,389	474,274	9,578	470,710	9,578	445,076
PDC 1990-A	132,789	110,188	2,075	96,478	2,075	40,420
PDC 1990-B	209,761	272,938	6,277	279,997	6,277	174,541
PDC 1990-C	328,478	465,099	20,294	499,472	20,294	191,414
PDC 1990-D	348,075	391,504	11,053	398,441	11,053	233,475
PDC 1991-A	258,683	381,466	3,032	371,295	3,032	237,756
PDC 1991-B	175,997	235,169	6,641	240,308	6,641	139,040
PDC 1991-C	258,400	361,782	5,599	362,360	5,599	217,098
PDC 1991-D	496,639	486,733	19,390	520,065	19,390	288,226
PDC 1992-A	274,711	64,004	-	44,323	-	-
PDC 1992-B	281,361	469,780	12,626	494,027	12,626	261,359
PDC 1992-C	603,396	1,196,101	30,430	1,258,264	30,430	523,275
PDC 1993-A	294,194	738,116	12,280	723,362	12,280	33,649
PDC 1993-B	236,736	255,651	11,358	274,798	11,358	-
PDC 1993-C	296,207	215,626	7,977	224,422	7,977	-
PDC 1993-D	282,819	269,292	9,967	281,565	9,967	-
PDC 1993-E	715,438	779,039	19,839	803,477	19,839	-
PDC 1994-A	449,641	164,870	5,444	171,532	5,444	-
PDC 1994-B	588,395	330,369	8,107	346,369	8,107	-
PDC 1994-C	513,159	249,511	6,928	260,650	6,928	-
PDC 1994-D	1,651,292	831,989	22,722	867,495	22,722	-
PDC 1995-A	320,601	162,450	4,520	159,852	4,520	-
PDC 1995-B	406,361	124,528	3,611	116,358	3,611	-
PDC 1995-C	462,546	132,301	3,745	126,309	3,745	-
PDC 1995-D	1,784,359	708,477	23,207	728,462	23,207	-
PDC 1996-A	560,324	311,321	7,883	292,885	7,883	-
PDC 1996-B	583,924	230,322	(6,925)	224,044	(6,925)	-
PDC 1996-C	858,359	219,169	12,243	216,086	12,243	-
PDC 1996-D	3,328,126	658,784	53,078	655,779	53,078	-
PDC 1997-A	906,311	185,332	10,932	181,850	10,932	-
PDC 1997-B	1,470,185	187,809	(8,363)	181,529	(8,363)	-
PDC 1997-C	1,314,409	358,070	28,110	327,826	28,110	-
PDC 1997-D	4,028,009	524,695	60,164	518,519	60,164	-
PDC 1998-A	1,146,690	471,749	20,632	484,424	20,632	-
PDC 1998-B	1,554,059	847,765	58,253	988,858	58,253	-
PDC 1998-C	1,699,280	681,292	33,541	755,296	33,541	-
PDC 1998-D	4,464,244	1,285,610	72,687	1,336,028	72,687	-
PDC 1999-A	1,044,161	656,007	49,249	772,090	49,249	-
PDC 1999-B	1,204,927	884,823	67,449	1,048,869	67,449	-
PDC 1999-C	1,541,544	843,520	52,635	959,109	52,635	-
PDC 1999-D	4,069,282	2,334,372	132,172	2,742,234	132,172	-
PDC 2000-A	1,078,086	651,261	24,247	677,767	24,247	-
PDC 2000-B	2,523,611	1,027,007	63,324	1,159,665	63,324	-
PDC 2000-C	3,046,796	886,892	74,810	1,117,840	74,810	-
PDC 2000-D	5,437,500	1,727,900	125,568	2,113,813	125,568	-
PDC 2001-A	2,040,976	652,215	46,345	735,057	46,345	-
PDC 2001-B	2,757,591	669,177	48,238	961,522	48,238	-
PDC 2001-C	2,311,423	532,929	44,254	763,418	44,254	-
PDC 2001-D	5,310,985	1,285,211	139,856	1,892,181	139,856	-
PDC 2002-A	1,554,586	472,781	43,631	734,119	43,631	-
PDC 2002-B	2,431,743	578,603	75,982	872,218	75,982	-
PDC 2002-C	2,052,809	522,992	62,927	787,056	62,927	-
PDC 2002-D	6,330,399	1,334,259	161,252	1,633,990	161,252	-
PDC 2003-A	1,845,062	766,573	97,822	706,116	97,822	-
PDC 2003-B	3,772,733	1,421,812	214,290	1,235,994	214,290	-
PDC 2003-C	3,805,448	1,113,212	202,701	964,886	202,701	-
PDC 2003-D	7,611,809	1,962,898	515,217	1,605,024	515,217	-
PDC 2004-A	6,419,029	1,756,348	780,393	1,146,994	780,393	-
PDC 2004-B	3,979,709	513,521	208,544	208,544	208,544	-

Partnership	Total Expenditures Net of Operating Costs	Total Revenues After Deducting Operating Costs(2) Total as of March 31, 2005	Three Months Ended March 31, 2005	Cash Distributions(3) Total as of March 31, 2005	Three Months Ended March 31, 2005	Aggregate Section 29 Tax Credits(4)
PDC 2004-C(5)	3,979,466	-	-	-	-	-
PDC 2004-D(6)	7,738,652	-	-	-	-	-
PDC 2005-A(7)	8,826,181	-	-	-	-	-
PDC 2005-B(8)	8,942,161	-	-	-	-	-

(1) Includes Managing General Partner share of drilling costs, exclusive of operating costs.
(2) Represents the accrued gross revenues credited from oil and gas production, excluding operating costs, landowners' royalty interests, overriding royalty interests, and other burdens.
(3) Represents the net cash received from the partnerships' cash distributions. All cash distributions to the managing general partner were made from operations.
(4) Wells drilled after December 31, 1992 do not qualify for the credit.
(5) Partnership funded in August 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution commenced in May 2005.
(6) Partnership funded in September 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.
(7) Partnership funded in February 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence in fall 2005.
(8) Partnership funded in April 2005; wells will be drilled in second and third quarters of 2005; first revenue distribution to commence in winter 2005/2006.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Tax Deductions and Tax Credits of Participants in Previous Partnerships

The following table reflects the participants' share of the previous limited partnerships' available tax deductions that were reported in the partnerships' tax returns and the share of tax deductions as a percentage of their subscriptions. The following percentages do not reflect the effect of the revenues from the partnerships' operations and are subject to audit adjustments by the Service. The table also reflects the aggregate Section 29 nonconventional fuel production credit as a percentage of the participants' initial investment over the life of each partnership through March 31, 2005, and the federal tax savings from deductions and tax credits based on the maximum marginal tax rate in each year. Wells drilled after December 31, 1992 does not qualify for the credit. The final column shows these tax shelter ratios calculated in accordance with Service regulations. Programs with anticipated tax shelter ratios of greater than 2:1 in any of the first five years must register as tax shelters. We do not expect any of the prior partnerships or the partnerships in the current program to exceed the 2:1 ratio. The following table is based on past experience and should not be considered as necessarily indicative of the results that may be expected in these partnerships. It is suggested that prospective subscribers consult with their tax advisors concerning their specific tax circumstances and the tax benefits available to them individually, which may materially vary in various circumstances.

	First Year Tax Deductions	Aggregate Deductions Thereafter	Aggregate Section 29 Tax Credits (1)	Estimated Federal Tax Savings (2)	Tax Shelter Ratio (3)
*Pennwest Petroleum Group 1984	70.87%	28.63%	23.22%	70.39%	1.5:1

	First Year Tax Deductions	Aggregate Deductions Thereafter	Aggregate Section 29 Tax Credits (1)	Estimated Federal Tax Savings (2)	Tax Shelter Ratio (3)
*Pennwest Petroleum Group 1985-A	69.51%	31.07%	30.83%	77.35%	1.6:1
*Petrowest Gas Group 1986-A	70.10%	32.19%	44.90%	91.33%	1.9 :1
*Petrowest Gas Group 1987	63.09%	37.99%	43.11%	80.53%	2.5:1
*Petrowest Gas Group 1987-B	68.70%	28.89%	33.90%	70.25%	2.2 :1
*PDC 1987	70.30%	35.42%	47.08%	86.40%	2.7:1
*PDC 1988	68.57%	36.61%	56.23%	91.52%	3.0 :1
*PDC 1988-B	66.70%	34.82%	28.92%	63.06%	2.0:1
*PDC 1988-C	69.20%	33.55%	35.39%	69.99%	2.3:1
*PDC 1989-P	63.68%	35.13%	47.99%	81.46%	2.7:1
*PDC 1989-A	69.80%	40.71%	50.61%	88.33%	2.9:1
*PDC 1989-B	69.10%	31.34%	22.98%	56.88%	1.8:1
*PDC 1990-A	67.92%	20.91%	11.50%	41.35%	1.3:1
*PDC 1990-B	71.50%	26.56%	31.43%	64.64%	2.1:1
*PDC 1990-C	70.60%	31.89%	22.01%	57.04%	1.8:1
*PDC 1990-D	69.70%	32.33%	25.34%	60.21%	1.9:1
*PDC 1991-A	69.80%	25.46%	34.72%	66.00%	2.2:1
*PDC 1991-B	67.00%	29.84%	29.84%	61.44%	2.0:1
*PDC 1991-C	69.60%	31.12%	31.74%	64.96%	2.1:1
*PDC 1991-D	69.80%	26.96%	21.92%	53.72%	1.7:1
*PDC 1992-A	68.24%	20.01%	15.31%	44.22%	1.4:1
*PDC 1992-B	69.60%	32.87%	35.09%	69.50%	2.3:1
*PDC 1992-C	69.20%	36.20%	32.76%	68.33%	2.2:1
*PDC 1993-A	69.00%	44.01%	4.94%	43.52%	1.3:1
*PDC 1993-B	68.10%	29.23%	-	36.07%	1.0:1
*PDC 1993-C	68.80%	26.37%	-	35.21%	1.0:1
*PDC 1993-D	68.60%	25.10%	-	34.62%	0.9:1
*PDC 1993-E	67.60%	28.52%	-	35.62%	1.0:1
*PDC 1994-A	87.70%	8.22%	-	37.98%	1.0:1
*PDC 1994-B	89.40%	11.02%	-	39.77%	1.0:1
*PDC 1994-C	89.70%	9.61%	-	39.33%	1.0:1
*PDC 1994-D	89.90%	10.38%	-	39.71%	1.0:1
*PDC 1995-A	89.60%	11.55%	-	40.05%	1.0:1
*PDC 1995-B	89.02%	7.96%	-	38.40%	1.0:1
*PDC 1995-C	89.71%	7.99%	-	38.69%	1.0:1
*PDC 1995-D	89.94%	8.79%	-	39.10%	1.0:1
*PDC 1996-A	89.94%	11.40%	-	40.13%	1.0:1
*PDC 1996-B	89.00%	10.36%	-	39.35%	1.0:1
*PDC 1996-C	89.42%	8.25%	-	38.68%	1.0:1
*PDC 1996-D	89.49%	7.93%	-	38.58%	1.0:1
*PDC 1997-A	89.50%	6.26%	-	37.92%	1.0:1
*PDC 1997-B	89.50%	5.43%	-	37.59%	0.9:1
*PDC 1997-C	89.50%	9.12%	-	39.05%	1.0:1
*PDC 1997-D	89.50%	6.25%	-	37.92%	1.0:1
*PDC 1998-A	89.50%	9.92%	-	39.37%	1.0:1
*PDC 1998-B	89.50%	11.61%	-	40.04%	1.0:1
*PDC 1998-C	89.50%	10.24%	-	39.50%	1.0:1
*PDC 1998-D	89.50%	7.25%	-	38.31%	1.0:1
*PDC 1999-A	89.50%	8.69%	-	38.88%	1.0:1
*PDC 1999-B	89.50%	10.90%	-	39.76%	1.0:1
*PDC 1999-C	89.50%	7.25%	-	38.31%	1.0:1
*PDC 1999-D	89.50%	7.33%	-	38.35%	1.0:1
*PDC 2000-A	89.50%	9.13%	-	39.06%	1.0:1
*PDC 2000-B	89.50%	7.26%	-	38.31%	1.0:1
PDC 2000-C	89.50%	6.55%	-	38.04%	1.0:1
PDC 2000-D	89.50%	6.05%	-	37.84%	1.0:1
PDC 2001-A	89.50%	3.23%	-	36.26%	0.9:1
PDC 2001-B	89.50%	3.76%	-	36.47%	0.9:1
PDC 2001-C	89.50%	6.05%	-	37.36%	1.0:1
PDC 2001-D	89.50%	5.74%	-	37.24%	1.0:1
PDC 2002-A	89.50%	7.53%	-	37.45%	1.0:1
PDC 2002-B	89.50%	5.51%	-	36.68%	1.0:1
PDC 2002-C	89.50%	6.94%	-	37.23%	1.0:1
PDC 2002-D	89.50%	3.90%	-	36.05%	0.9:1
PDC 2003-A	89.50%	6.07%	-	33.45%	1.0:1
PDC 2003-B	89.50%	4.08%	-	32.75%	0.9:1
PDC 2003-C	89.50%	5.14%	-	33.12%	0.9:1

	First Year Tax Deductions	Aggregate Deductions Thereafter	Aggregate Section 29 Tax Credits (1)	Estimated Federal Tax Savings (2)	Tax Shelter Ratio (3)
PDC 2003-D	89.50%	3.27%	-	32.47%	0.9:1
PDC 2004-A	89.90%	0.80%	-	31.61%	0.9:1
PDC 2004-B	89.90%	0.92%		31.65%	0.9:1
PDC 2004-C(4)	89.90%	0.00%	-	31.47%	0.9:1
PDC 2004-D(5)	89.90%	0.00%	-	31.47%	0.9:1
PDC 2005-A(6)	89.90%	0.00%	-	31.47%	0.9:1
PDC 2005-B(7)	89.90%	0.00%	-	31.47%	0.9:1

*Partnerships in existence for over five years.

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(1) Wells drilled after December 31, 1992 do not qualify for the credit.

(2) The Estimated Federal Tax Savings column reflects the percentage savings in taxes which would have been paid by an investor had he not had the use of the various deductions and credits available to a partner in the program and it assumes full use of deductions and tax credits at maximum federal income tax rates for individuals of 50% in 1984 - 1986, 40% in 1987 and 1988, and 33% in 1989 and 1990, 31% in 1991-1992, 36% in 1993, 39.6% in 1994 - 2000, 39.1% in 2001, 38.6% in 2002 and 35% in 2003 and 2004.

(3) Total deductions plus 200% of credits generated for partnerships first offered before December 31, 1986. Total deductions plus 350% of credits generated for partnerships offered after December 31, 1986.

(4) Partnership funded in August 2004.

(5) Partnership funded in September 2004.

(6) Partnership funded in February 2005.

(7) Partnership funded in April 2005.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Percentage of Gross Return on Subscriptions Through March 31, 2005 From Cash Distributions, Tax Savings from Deductions and Tax Credits (1)

Program	Cash Distribution(2)	Cumulative Section 29 Credit (3)	Total Cash And Tax Credit	Tax Deductions Tax Effected (4)	Total Return of Cash, Tax Deduction(5)	Year/ Months Producing
*Pennwest Petroleum 1984	56.09%	23.22%	79.30%	51.15%	130.46%	20/0
*Pennwest Petroleum 1985	49.26%	30.83%	80.09%	50.54%	130.63%	19/1
**Petrowest Gas Group 1986	58.74%	44.90%	103.64%	50.53%	154.17%	18/0
**Petrowest Gas Group 1987	78.73%	43.11%	121.84%	41.47%	163.30%	17/3
**Petrowest Gas Group 1987-B	41.80%	33.90%	75.70%	40.25%	115.95%	17/0
**PDC 1987	66.49%	47.08%	113.57%	43.55%	157.12%	16/10
**PDC 1988	87.68%	56.23%	143.91%	39.50%	183.41%	16/4
**PDC 1988-B	27.89%	28.92%	56.81%	38.20%	95.01%	16/0
**PDC 1988-C	44.55%	35.39%	79.95%	38.71%	118.66%	15/10
**PDC 1989-P	71.74%	47.99%	119.73%	37.42%	157.15%	15/4
**PDC 1989-A	90.03%	50.61%	140.63%	42.15%	182.78%	15/0
**PDC 1989-B	50.83%	22.98%	73.81%	37.92%	111.73%	14/10
**PDC 1990-A	29.43%	11.50%	40.93%	33.41%	74.34%	14/5
**PDC 1990-B	51.12%	31.43%	82.55%	37.13%	119.69%	14/3
**PDC 1990-C	58.49%	22.01%	80.50%	39.13%	119.63%	13/11
**PDC 1990-D	46.44%	25.34%	71.78%	38.95%	110.74%	13/10
**PDC 1991-A	54.58%	34.72%	89.30%	35.09%	124.39%	13/5
**PDC 1991-B	50.80%	29.84%	80.64%	35.47%	116.11%	13/2

Program	Cash Distribution(2)	Cumulative Section 29 Credit (3)	Total Cash And Tax Credit	Tax Deductions Tax Effected (4)	Total Return of Cash, Tax Deduction(5)	Year/ Months Producing
**PDC 1991-C	52.98%	31.74%	84.72%	37.25%	121.97%	13/0
**PDC 1991-D	40.51%	21.92%	62.44%	35.66%	98.10%	12/10
**PDC 1992-A	19.89%	15.31%	35.20%	32.44%	67.64%	12/5
**PDC 1992-B	64.70%	35.09%	99.80%	38.50%	138.30%	12/3
**PDC 1992-C	78.68%	32.76%	111.44%	39.78%	151.23%	12/0
**PDC 1993-A	105.58%	4.94%	110.52%	43.10%	153.62%	11/10
**PDC 1993-B	51.11%	-	51.11%	39.96%	91.07%	11/5
**PDC 1993-C	36.82%	-	36.82%	39.01%	75.83%	11/2
**PDC 1993-D	46.73%	-	46.73%	38.37%	85.10%	11/0
**PDC 1993-E	51.14%	-	51.14%	39.47%	90.61%	10/9
**PDC 1994-A	33.18%	-	33.18%	41.82%	75.00%	10/5
**PDC 1994-B	50.53%	-	50.53%	43.78%	94.32%	10/2
**PDC 1994-C	43.28%	-	43.28%	43.30%	86.58%	10/0
**PDC 1994-D	45.19%	-	45.19%	43.72%	88.91%	9/10
**PDC 1995-A	43.30%	-	43.30%	44.10%	87.40%	9/6
**PDC 1995-B	25.74%	-	25.74%	42.28%	68.02%	9/3
**PDC 1995-C	24.14%	-	24.14%	42.60%	66.74%	9/0
**PDC 1995-D	36.67%	-	36.67%	43.05%	79.71%	8/10
**PDC 1996-A	60.01%	-	60.01%	44.18%	104.19%	8/5
**PDC 1996-B	49.62%	-	49.62%	43.32%	92.93%	8/1
**PDC 1996-C	35.74%	-	35.74%	42.58%	78.32%	7/11
**PDC 1996-D	35.38%	-	35.38%	42.48%	77.85%	7/10
**PDC 1997-A	34.07%	-	34.07%	41.75%	75.82%	7/5
**PDC 1997-B	24.09%	-	24.09%	41.39%	65.48%	7/1
**PDC 1997-C	43.59%	-	43.59%	43.00%	86.58%	6/11
**PDC 1997-D	23.48%	-	23.48%	41.75%	65.23%	6/9
**PDC 1998-A	46.40%	-	46.40%	43.35%	89.75%	6/4
**PDC 1998-B	54.46%	-	54.46%	44.08%	98.54%	6/1
**PDC 1998-C	46.31%	-	46.31%	43.49%	89.80%	5/11
**PDC 1998-D	35.10%	-	35.10%	42.18%	77.28%	5/9
**PDC 1999-A	63.63%	-	63.63%	42.81%	106.44%	5/5
*PDC 1999-B	74.37%	-	74.37%	43.78%	118.14%	5/1
*PDC 1999-C	53.08%	-	53.08%	42.18%	95.27%	4/11
*PDC 1999-D	57.35%	-	57.35%	42.22%	99.57%	4/9
*PDC 2000-A	53.54%	-	53.54%	43.00%	96.55%	4/5
*PDC 2000-B	39.12%	-	39.12%	42.19%	81.31%	4/1
*PDC 2000-C	31.24%	-	31.24%	41.88%	73.11%	3/10
*PDC 2000-D	32.87%	-	32.87%	41.66%	74.53%	3/8
*PDC 2001-A	30.67%	-	30.67%	39.97%	70.64%	3/5
*PDC 2001-B	29.48%	-	29.48%	40.20%	69.67%	3/1
*PDC 2001-C	27.90%	-	27.90%	41.18%	69.09%	2/11
*PDC 2001-D	30.20%	-	30.20%	41.05%	71.25%	2/9
*PDC 2002-A	40.24%	-	40.24%	41.33%	81.57%	2/5
*PDC 2002-B	30.54%	-	30.54%	40.48%	71.02%	2/1
*PDC 2002-C	32.55%	-	32.55%	41.08%	73.63%	1/11
*PDC 2002-D	22.01%	-	22.01%	39.79%	61.80%	1/9
*PDC 2003-A	33.30%	-	33.30%	37.27%	70.57%	1/5
*PDC 2003-B	28.50%	-	28.50%	36.50%	65.00%	1/1
*PDC 2003-C	22.06%	-	22.06%	36.91%	58.97%	0/11
*PDC 2003-D	18.34%	-	18.34%	36.18%	54.53%	0/9
*PDC 2004-A	15.80%	-	15.80%	35.22%	51.02%	0/5
*PDC 2004-B	4.63%	-	4.63%	35.27%	39.90%	0/2
*PDC 2004-C(6)	0.00%	-	0.00%	35.06%	35.06%	0/0
*PDC 2004-D(7)	0.00%	-	0.00%	35.06%	35.06%	0/0
*PDC 2005-A(8)	0.00%	-	0.00%	35.06%	35.06%	0/0
*PDC 2005-B(9)	0.00%	-	0.00%	35.06%	35.06%	0/0

* Program contains oil and gas production.

** Program contains gas production.

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(1) This table assumes investors were able to fully utilize all tax benefits at the maximum marginal Federal rate plus an assumed state rate of 4%.

(2) Cash distributions to investors divided by investors' initial investment.

(3) Credit earned on qualified production. Wells drilled after December 31, 1992 do not qualify for the credit.
(4) Tax savings from deductions assuming investor is in the highest marginal bracket. Rates used (which are based on the maximum marginal federal income tax rate for individuals plus an assumed state rate of 4%) were 54% in 1984, 1985 and 1986, 42.5% in 1987, 37% in 1988, 1989 and 1990, 35% in 1991 and 1992, 40% in 1993, 43.6% in 1994 - 2000, 43.1% in 2001, 42.6% in 2002 and 39% in 2003 through 2005. For purposes of this calculation, no effect has been given for the possible deduction of state income taxes for federal income tax purposes.
(5) This column represents the sum of the percentage amounts set forth in columns 1, 2, and 4 of this table.
(6) Partnership funded in August 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution commenced in May 2005.
(7) Partnership funded in September 2004; wells were drilled in the fourth quarter of 2004 and the first quarter of 2005; first revenue distribution to commence in June 2005.
(8) Partnership funded in February 2005; wells will be drilled in the second and third quarters of 2005; first revenue distribution to commence fall 2005.

(9) Partnership funded in April 2005; wells were drilled in second and third quarters of 2005; first revenue distribution to commence in winter 2005/2006.

Partnership Estimated Proved Reserves and Future Net Revenues

The following table presents information regarding the public drilling programs sponsored by the Managing General Partner. The table reflects with respect to each partnership the estimated proved reserves and future net reserves as of January 1, 2005. The information presented in the following table has been prepared in conformity with generally accepted accounting principles. The information presented has been derived from reports prepared by an independent petroleum consultant, Wright & Company, Inc. and by the Managing General Partner's petroleum engineers as noted below.

Partnership Proved Reserves and Future Net Revenues as of January 1, 2005 (1)

Partnership	Category of Proved Reserves	Net Oil Reserves (Bbl)	Net Gas Reserves (Mcf)	Estimated Future Net Revenues	Present Value Discounted at 10% Per Annum
PDC 1989-A(2)	Proved Developed	853	690,818	$3,030,141	$769,940
	Proved Undeveloped	-	-	-	-
	Totals	853	690,818	$3,030,141	$769,940
PDC 1989-B(2)	Proved Developed	-	995,697	$3,721,324	$1,255,532
	Proved Undeveloped	-	-	-	-
	Totals	-	995,697	$3,721,324	$1,255,532
PDC 1990-A(2)	Proved Developed	-	180,170	$539,989	$300,070
	Proved Undeveloped	-	-	-	-
	Totals	-	180,170	$539,989	$300,070
PDC 1990-B(2)	Proved Developed	-	1,106,281	$5,112,621	$918,891
	Proved Undeveloped	-	-	-	-
	Totals	-	1,106,281	$5,112,621	$918,891
PDC 1990-C(2)	Proved Developed	-	1,869,190	$8,474,722	$2,695,155

Partnership	Category of Proved Reserves	Net Oil Reserves (Bbl)	Net Gas Reserves (Mcf)	Estimated Future Net Revenues	Present Value Discounted at 10% Per Annum
	Proved Undeveloped	-	-	-	-
	Totals	-	1,869,190	$8,474,722	$2,695,155
PDC 1990-D(2)	Proved Developed	-	1,776,097	$8,041,958	$1,965,673
	Proved Undeveloped	-	-	-	-
	Totals	-	1,776,097	$8,041,958	$1,965,673
PDC 1991-A(2)	Proved Developed	1,056	864,405	$4,017,053	$1,011,404
	Proved Undeveloped	-	-	-	-
	Totals	1,056	864,405	$4,017,053	$1,011,404
PDC 1991-B(2)	Proved Developed	-	807,539	$3,523,741	$1,066,471
	Proved Undeveloped	-	-	-	-
	Totals	-	807,539	$3,523,741	$1,066,471
PDC 1991-C(2)	Proved Developed	466	1,039,061	$4,322,594	$1,346,854
	Proved Undeveloped	-	-	-	-
	Totals	466	1,039,061	$4,322,594	$1,346,854
PDC 1991-D(2)	Proved Developed	311	1,718,984	$7,833,135	$2,934,377
	Proved Undeveloped	-	-	-	-
	Totals	311	1,718,984	$7,833,135	$2,934,377
PDC 1992-A(2)	Proved Developed	-	245,499	$755,963	$368,615
	Proved Undeveloped	-	-	-	-
	Totals	-	245,499	$755,963	$368,615
PDC 1992-B(2)	Proved Developed	-	1,589,449	$7,200,618	$2,057,960
	Proved Undeveloped	-	-	-	-
	Totals	-	1,589,449	$7,200,618	$2,057,960
PDC 1992-C(2)	Proved Developed	189	3,042,676	$13,716,218	$5,172,499
	Proved Undeveloped	-	-	-	-
	Totals	189	3,042,676	$13,716,218	$5,172,499
PDC 1993-A(2)	Proved Developed	-	1,491,761	6,910,359	$1,730,714
	Proved Undeveloped	-	-	-	-
	Totals	-	1,491,761	$6,910,359	$1,730,714
PDC 1993-B(2)	Proved Developed	-	1,146,346	$5,562,216	$1,613,468
	Proved Undeveloped	-	-	-	-
	Totals	-	1,146,346	$5,562,216	$1,613,468
PDC 1993-C(2)	Proved Developed	-	1,765,453	$8,534,832	$2,137,755
	Proved Undeveloped	-	-	-	-
	Totals	-	1,765,453	$8,534,832	$2,137,755
PDC 1993-D(2)	Proved Developed	622	1,344,459	$6,385,350	$1,611,058
	Proved Undeveloped	-	-	-	-
	Totals	622	1,344,459	$6,385,350	$1,611,058

Partnership	Category of Proved Reserves	Net Oil Reserves (Bbl)	Net Gas Reserves (Mcf)	Estimated Future Net Revenues	Present Value Discounted at 10% Per Annum
PDC 1993-E(2)	Proved Developed	2,978	3,175,130	$14,973,612	$3,800,354
	Proved Undeveloped	-	-	-	-
	Totals	2,978	3,175,130	$14,973,612	$3,800,354
PDC 1994-A(2)	Proved Developed	-	848,238	$3,872,423	$824,198
	Proved Undeveloped	-	-	-	-
	Totals	-	848,238	$3,872,423	$824,198
PDC 1994-B(2)	Proved Developed	-	858,601	$3,677,773	$1,198,686
	Proved Undeveloped	-	-	-	-
	Totals	-	858,601	$3,677,773	$1,198,686
PDC 1994-C(2)	Proved Developed	-	887,533	$3,732,264	$951,273
	Proved Undeveloped	-	-	-	-
	Totals	-	887,533	$3,732,264	$951,273
PDC 1994-D(2)	Proved Developed	-	2,368,479	$9,733,921	$3,235,913
	Proved Undeveloped	-	-	-	-
	Totals	-	2,368,479	$9,733,921	$3,235,913
PDC 1995-A(2)	Proved Developed	-	316,087	$1,046,775	$500,141
	Proved Undeveloped	-	-	-	-
	Totals	-	316,087	$1,046,775	$500,141
PDC 1995-B(2)	Proved Developed	54	433,250	$1,721,577	$443,145
	Proved Undeveloped	-	-	-	-
	Totals	54	433,250	$1,721,577	$443,145
PDC 1995-C(2)	Proved Developed	-	572,831	$2,302,463	$763,116
	Proved Undeveloped	-	-	-	-
	Totals	-	572,831	$2,302,463	$763,116
PDC 1995-D(2)	Proved Developed	518	1,730,850	$6,545,043	$2,883,210
	Proved Undeveloped	-	-	-	-
	Totals	518	1,730,850	$6,545,043	$2,883,210
PDC 1996-A(2)	Proved Developed	-	406,450	$1,442,401	$759,771
	Proved Undeveloped	-	-	-	-
	Totals	-	406,450	$1,442,401	$759,771
PDC 1996-B(2)	Proved Developed	-	825,086	$2,919,607	$1,290,302
	Proved Undeveloped	-	-	-	-
	Totals	-	825,086	$2,919,607	$1,290,302
PDC 1996-C(2)	Proved Developed	-	868,498	$2,961,196	$1,309,671
	Proved Undeveloped	-	-	-	-
	Totals	-	868,498	$2,961,196	$1,309,671

Partnership	Category of Proved Reserves	Net Oil Reserves (Bbl)	Net Gas Reserves (Mcf)	Estimated Future Net Revenues	Present Value Discounted at 10% Per Annum
PDC 1996-D(2)	Proved Developed	-	4,126,447	$15,113,713	$6,101,935
	Proved Undeveloped	-	-	-	-
	Totals	-	4,126,447	$15,113,713	$6,101,935
PDC 1997-A(2)	Proved Developed	-	861,390	$3,473,217	$1,574,996
	Proved Undeveloped	-	-	-	-
	Totals	-	861,390	$3,473,217	$1,574,996
PDC 1997-B(2)	Proved Developed	-	963,490	$3,304,147	$1,731,933
	Proved Undeveloped	-	-	-	
	Totals	-	963,490	$3,304,147	$1,731,933
PDC 1997-C(2)	Proved Developed	-	1,835,457	$7,218,945	$3,213,465
	Proved Undeveloped	-	-	-	
	Totals	-	1,835,457	$7,218,945	$3,213,465
PDC 1997-D(2)	Proved Developed	-	3,296,920	$15,342,174	$6,842,026
	Proved Undeveloped	-	-	-	
	Totals	-	3,296,920	$15,342,174	$6,842,026
PDC 1998-A(2)	Proved Developed	-	1,974,522	$7,447,166	$3,627,675
	Proved Undeveloped	-	-	-	-
	Total	-	1,974,522	$7,447,166	$3,627,675
PDC 1998-B(2)	Proved Developed	-	3,208,977	$12,945,989	$5,802,775
	Proved Undeveloped	-	-	-	-
	Totals	-	3,208,997	$12,945,989	$5,802,775
PDC 1998-C(2)	Proved Developed	-	3,151,021	$10,980,462	$5,309,853
	Proved Undeveloped	-	-	-	-
	Totals	-	3,151,021	$10,980,462	$5,309,853
PDC 1998-D(2)	Proved Developed	-	6,037,732	$22,301,029	$10,898,151
	Proved Undeveloped	-	-	-	-
	Totals	-	6,037,732	$22,301,029	$10,898,151
PDC 1999-A(2)	Proved Developed	-	2,723,401	$11,092,383	$5,120,066
	Proved Undeveloped	-	-	-	-
	Totals	-	2,723,401	$11,092,383	$5,120,066
PDC 1999-B(2)	Proved Developed	12,442	3,968,194	$17,378,037	$8,288,264
	Proved Undeveloped	-	-	-	-
	Totals	12,442	3,968,194	$17,378,037	$8,288,264
PDC 1999-C(2)	Proved Developed	55,182	3,390,860	$15,863,772	$7,903,927
	Proved Undeveloped	-	-	-	-
	Totals	55,182	3,390,860	$15,986,772	$7,902,927

Partnership	Category of Proved Reserves	Net Oil Reserves (Bbl)	Net Gas Reserves (Mcf)	Estimated Future Net Revenues	Present Value Discounted at 10% Per Annum
PDC 1999-D(2)	Proved Developed	154,452	8,094,363	$36,651,730	$18,414,760
	Proved Undeveloped	-	-	-	-
	Totals	154,452	8,094,363	$36,651,730	$18,414,760
PDC 2000-A(2)	Proved Developed	140,073	1,311,820	$10,858,897	$5,804,646
	Proved Undeveloped	-	-	-	-
	Totals	140,073	1,311,820	$10,858,897	$5,804,646
PDC 2000-B(2)	Proved Developed	196,380	3,334,104	$20,142,020	$10,454,662
	Proved Undeveloped	-	-	-	-
	Totals	196,380	3,334,104	$20,142,020	$10,454,662
PDC 2000-C(2)	Proved Developed	153,291	4,197,135	$21,096,320	$10,921,137
	Proved Undeveloped	-	-	-	-
	Totals	153,291	4,197,135	$21,096,320	$10,921,137
PDC 2000-D(2)	Proved Developed	390,240	390,240	$37,848,715	$19,920,141
	Proved Undeveloped	-	-	-	-
	Totals	390,240	6,125,500	$37,848,715	$19,920,141
PDC 2001-A(2)	Proved Developed	201,090	2,110,411	$15,742,539	$8,202,434
	Proved Undeveloped	-	-	-	-
	Totals	201,090	2,110,411	$15,742,539	$8,202,434
PDC 2001-B(2)	Proved Developed	168,472	2,735,086	$16,292,897	$8,341,757
	Proved Undeveloped	-	-	-	-
	Totals	168,472	2,735,086	$16,292,897	$8,341,757
PDC 2001-C(2)	Proved Developed	186,507	2,562,327	$17,225,754	$8,595,590
	Proved Undeveloped	-	-	-	-
	Totals	186,507	2,562,327	$17,225,754	$8,595,590
PDC 2001-D(2)	Proved Developed	293,816	6,825,053	$36,949,730	$18,206,574
	Proved Undeveloped	-	-	-	-
	Totals	293,816	6,825,053	$36,949,730	$18,206,574
PDC 2002-A(2)	Proved Developed	94,052	3,080,324	$15,084,939	$7,379,607
	Proved Undeveloped	-	-	-	-
	Totals	94,052	3,080,324	$15,084,939	$7,379,607
PDC 2002-B(2)	Proved Developed	146,439	3,136,893	$16,951,740	$8,656,331
	Proved Undeveloped	-	-	-	-
	Totals	146,439	3,136,893	$16,951,740	$8,656,331
PDC 2002-C(2)	Proved Developed	186,146	2,348,242	$16,311,086	$8,074,540
	Proved Undeveloped	-	-	-	-
	Totals	186,146	2,348,242	$16,311,086	$8,074,540
PDC 2002-D(3)	Proved Developed	412,710	6,764,630	$41,339,496	$20,187,514
	Proved Undeveloped	-			
	Totals	412,710	6,764,630	$41,339,496	$20,187,514

Partnership	Category of Proved Reserves	Net Oil Reserves (Bbl)	Net Gas Reserves (Mcf)	Estimated Future Net Revenues	Present Value Discounted at 10% Per Annum
PDC 2003-A(3)	Proved Developed	187,792	2,865,330	$18,213,344	$8,790,715
	Proved Undeveloped	-	-	-	-
	Totals	187,792	2,865,330	$18,213,344	$8,790,715
PDC 2003-B(3)	Proved Developed	356,749	5,805,492	$36,560,984	$17,680,086
	Proved Undeveloped	-	-	-	-
	Totals	356,749	5,805,492	$36,560,984	$17,680,086
PDC 2003-C(3)	Proved Developed	370,690	4,697,578	$33,093,340	$16,637,139
	Proved Undeveloped	-	-	-	-
	Totals	370,690	4,697,578	$33,093,340	$16,637,139
PDC 2003-D(3)	Proved Developed	510,288	12,464,499	$67,035,250	$32,250,301
	Proved Undeveloped	-	-	-	-
	Totals	510,288	12,464,499	$67,035,250	$32,250,301
PDC 2004-A(3)	Proved Developed	597,109	14,862,130	$84,348,023	$40,972,547
	Proved Undeveloped	-	-	-	-
	Totals	597,109	14,862,130	$84,348,023	$40,972,547
PDC 2004-B(3)	Proved Developed	355,252	9,192,837	$52,112,777	$27,742,859
	Proved Undeveloped	-	-	-	-
	Totals	355,252	9,192,837	$52,112,777	$27,742,859
PDC 2004-C(3)(4)	Proved Developed	146,092	6,688,427	$32,832,336	$16,872,443
	Proved Undeveloped	-	-	-	-
	Totals	146,092	6,688,427	$32,832,336	$16,872,443
PDC 2004-D(3)(5)	Proved Developed	179,422	3,615,232	$21,169,611	$11,844,074
	Proved Undeveloped	-	-	-	-
	Totals	179,422	3,615,232	$21,169,611	$11,844,074

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

(1) For the partnerships PDC 1989-A through PDC 1992-C and for PDC 1994-A through PDC 2002-C, we own 20% of the reserves listed and the investor partners own 80% of the reserves listed above. In the PDC 1993-A, PDC 1993-B, PDC 1993-C, PDC 1993-D and PDC 1993-E Limited Partnerships, we own 18% of the reserves listed and the Investor Partners own 82% of the reserves listed above.
(2) Reserve reports prepared by our petroleum engineers.
(3) Reserve reports prepared by an independent petroleum consultant, Wright & Company, Inc.
(4) Reserve report includes 19 of the 23 total wells drilled before December 31, 2004.
(5) Reserve report includes the 17 of the 44 wells drilled before December 31, 2004.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

Participants' Estimated Future and Total Payout and Payout Period For Partnerships Formed Since 1999 with Colorado Operations Based on Returns to Date and 2004 Reserve Reports

The following table shows the estimated payout and payout period for partnerships formed by PDC since 1999. PDC began drilling in Colorado in 1999, and all of the drilling activities for the remaining 2005 partnerships are currently planned for the three Colorado fields. The payout amounts and periods are based on the partnership reserve reports at December 31, 2004. The reserve reports assume that oil and gas prices remain constant at the December 2004 levels. The averages for December 2004 were $5.26 per Mcf of natural gas and $35.13 per barrel of oil. Changes in these prices, the estimated reserves, the estimated operating expenses and other factors would result in changes in the payout amounts and payout periods.

Partnership	Cash Distributions Through 12/31/2004	Estimated Future Net Revenues 12/31/2004	Cash Distributions Plus Estimated Future Net Revenues	Subscriptions From Participants	Year Payout (2) Anticipated
PDC 1999-A	$ 3,054,664	$ 8,873,906	$ 11,928,570	$ 4,800,739	2007
PDC 1999-B	4,119,836	13,902,430	18,022,266	5,539,893	2006
PDC 1999-C	3,762,408	12,789,418	16,551,826	7,087,559	2008
PDC 1999-D	10,729,508	29,321,382	40,050,890	18,709,342	2008
PDC 2000-A	2,653,860	8,687,118	11,340,978	4,956,718	2008
PDC 2000-B	4,539,066	16,113,616	20,652,682	11,602,809	2010
PDC 2000-C	4,375,551	16,877,056	21,252,607	14,008,256	2013
PDC 2000-D	8,218,054	30,278,972	38,497,026	25,000,000	2012
PDC 2001-A	2,878,260	12,594,031	15,472,291	9,383,798	2011
PDC 2001-B	3,737,023	13,034,318	16,771,341	12,678,577	2015
PDC 2001-C	2,965,514	13,780,603	16,746,117	10,627,234	2013
PDC 2001-D	7,373,433	29,559,784	36,933,217	24,418,322	2013
PDC 2002-A	2,875,972	12,067,951	14,943,923	7,147,522	2010
PDC 2002-B	3,414,865	13,561,392	16,976,257	11,180,426	2013
PDC 2002-C	3,072,131	13,048,869	16,121,000	9,438,203	2012
PDC 2002-D(1)	6,405,612	33,071,597	39,477,209	29,105,281	2016
PDC 2003-A(1)	2,824,482	14,570,675	17,395,157	8,483,045	2011
PDC 2003-B(1)	4,943,994	29,248,787	34,192,781	17,345,901	2011
PDC 2003-C(1)	3,859,556	26,474,672	30,334,228	17,496,314	2012
PDC 2003-D(1)	6,420,112	53,628,200	60,048,312	34,996,823	2013
PDC 2004-A(1)	4,587,985	67,478,418	72,066,403	29,030,865	2010
PDC 2004-B(1)	834,178	41,690,222	42,524,400	17,998,735	2010

(1) Reserve reports prepared by an independent petroleum consultant, Wright & Company, Inc.
(2) "Payout" occurs when the participants have received cash equal to their respective original subscription amounts.

You should not consider operating results obtained by these prior partnerships as indicative of the operating results obtainable by the partnerships.

TAX CONSIDERATIONS

We attach the tax opinion of Duane Morris LLP to the prospectus as Appendix D. You should review Appendix D in its entirety before investing in the program. All references in this "Tax Considerations" section are to the tax opinion set forth in Appendix D.

The following is a summary of the opinions of Duane Morris LLP, counsel to the partnerships, which represent counsel's opinions on all material federal income tax consequences to the partnership and to you as an investor partner. There may be aspects of your particular tax situation which are not addressed in the following discussion or in Appendix D. Additionally, the resolution of tax issues depends upon future facts and circumstances not known to counsel as of the date of this prospectus; thus, no assurance as to the final resolution of these issues should be drawn from the following discussion.

The following statements are based upon the provisions of the Internal Revenue Code of 1986, which we refer to as the "Code," existing and proposed regulations thereunder, current administrative rulings, and court decisions. It is possible that legislative or administrative changes or future court decisions may significantly affect the statements and opinions expressed in this prospectus. Changes could be retroactive with respect to the transactions prior to the date of the 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 Internal Revenue Service, which we refer to as the "Service," and any challenge could be successful. Thus, there can be no assurance that all of the anticipated tax benefits of an investment in the partnership will be realized.

Counsel's opinion is based upon the transactions described in this prospectus, which we refer to as the "transaction," and upon facts as they have been represented to counsel or determined by it as of the date of the opinion. Any alteration of the facts may adversely affect the opinions rendered.

Because of the factual nature of the inquiry, it is not possible to reach a judgment as to the outcome on the merits (either favorable or unfavorable) of some material federal income tax issues as described more fully in this section.

Summary of Conclusions

Opinions expressed: The following is a summary of the specific opinions expressed by counsel. To fully understand the tax considerations of an investment in the program, you should read the discussion of these matters set forth in the tax opinion in Appendix D.

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

b. The partnership will be treated as a partnership for federal income tax purposes and not as an association taxable as a corporation or as a "publicly traded partnership." See "General Tax Effects of Partnership Structure."

c. To the extent the partnership's wells are timely drilled and amounts are timely paid, the partners will be entitled to their pro rata share of the partnership's intangible drilling and development costs paid in 2004 with respect to the partnerships designated "PDC 2004- Limited Partnership," in 2005 with respect to the partnerships designated "PDC 2005- Limited Partnership," and in 2006 with respect to the partnerships designated "PDC 2006- Limited Partnership." However, these intangible drilling and development costs deductions may be subject to recapture, which could have the effect of requiring an investor to recognize additional ordinary income in later years. See "Intangible Drilling and Development Costs Deductions."

d. Neither the at risk nor the limitations related to the adjusted basis of an investor in his or her Partnership interest will limit the deductibility of losses generated from the partnership to the extent that the investor contributes cash to the partnership from "personal funds" (funds not borrowed by the investor). See "Basis and At Risk Limitations."

e. An additional general partner's interest will not be considered an interest in a passive activity within the meaning of Code Section 469 and losses generated while the general partner interest is so held will not be limited by the passive activity provisions. See "Passive Loss Limitations."

f. Limited partners' interests (other than those held by additional general partners who convert their interests into limited partners' interests) will be considered interests in a passive activity within the meaning of Code Section 469 and losses generated therefrom will be limited by the passive activity provisions. See "Passive Loss Limitations."

g. The partnership will not be terminated solely as the result of the conversion of partnership interests. See "Conversion of Interests."

h. To the extent provided in this section of the prospectus, the partners' distributive shares of partnership tax items will be determined and allocated substantially in accordance with the terms of the limited partnership agreement. See "Partnership Allocations."

i. The partnership will not be required to register with the Service as a tax shelter; the partners will not be required to disclose the partnership as a tax shelter on Form 8886; and the organizers of the partnership will not be required to maintain a list of the partners as participants in a tax shelter. See "Tax Shelter Rules."

No opinion expressed: Due to the essentially factual nature of the question, counsel expresses no opinion on the following:

The impact of an investment in the partnership on an investor's alternative minimum tax. See "Alternative Minimum Tax."

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 engaging in the transaction. See "Profit Motive."

Whether each partner will be entitled to percentage depletion, due to the factual nature of determining the status of the partner as an independent producer and the partner's other oil and gas production. See "Depletion Deductions."

Without any assistance from us, some partners may choose to borrow the funds necessary to acquire a Unit and may incur interest expense in connection with that borrowing. Whether any interest incurred by a partner with respect to any borrowings will be deductible or subject to limitations on deductibility, due to the factual nature of the issue. See "Interest Deductions."

Whether the fees to be paid to us and to third parties will be deductible, due to the factual nature of the issue. 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, counsel is unable to express an opinion regarding that treatment. See "Transaction Fees."

General Information: Certain matters contained in this "Tax Considerations" section 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, local, and self-employment tax. See "General Tax Effects of Partnership Structure," "Gain or Loss on Sale of Properties or Units," "Partnership Distributions," "Administrative Matters," "Accounting Methods and Periods," "Social Security Benefits; Self-Employment Tax," and "State and Local Tax."

Facts and Representations: The opinions of counsel are also based upon the facts described in this prospectus and upon representations made to counsel by us for the purpose of permitting counsel to render its opinions, including the following representations with respect to the program:

The limited partnership agreement to be entered into by and among the investor partners and us and any amendments to the agreement will be duly executed and will be made available to you upon written request. The limited partnership agreement will be duly recorded in all places required under the West Virginia Uniform Limited Partnership Act for the due formation of the partnership and for its continuation in accordance with the terms of the limited partnership agreement. The partnership will at all times be operated in accordance with the terms of the limited partnership agreement, the prospectus, and the West Virginia Act.

No election will be made by the partnership, investor partners, or us to be excluded from the application of the provisions of Subchapter K of the Code.

The partnership will own an operating mineral interest, as defined in the Code and in the Regulations, in all of the drill sites and none of the partnership's revenues will be from non-working interests.

The amounts that will be paid to the Managing General Partner as drilling fees, operating fees, and other fees will be amounts that would not exceed amounts that would be ordinarily paid for similar transactions between persons having no affiliation and dealing with each other at arms' length.

We will cause the partnership to properly elect to deduct currently all intangible drilling and development costs.

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

The drilling and operating agreement to be entered into by and between the partnership and us will be duly executed and will govern the drilling of the partnership's wells. All partnership wells will be spudded by not later than March 30, 2005 for partnerships designated "PDC 2004- Limited Partnership," March 30, 2006 for partnerships designated "PDC 2005- Limited Partnership" and March 30, 2007 for partnerships designated "PDC 2006- Limited Partnership." Thereafter, each well will be completed with due diligence, if completion is warranted.

The drilling and operating agreement will be duly executed and will govern the operation of the partnership's wells.

9. Based upon our review of our experience with our previous drilling programs since 1984 (see "Prior Activities – Tax Deductions and Tax Credits of Participants in Previous Partnerships," above) and upon the intended operations of the partnership, we have represented that the sum of (a) the aggregate deductions, including depletion deductions, and (b) 350 percent of the aggregate 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 cash invested by the partners in the partnership as of those dates. In that regard, we have reviewed the economics of our similar oil and gas drilling programs for the past several years, and have represented that we have determined that none of those programs has resulted in a tax shelter ratio greater than two to one. Further, we have represented that the deductions 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 believe that no person could reasonably infer from representations made, or to be made, in connection with the offering of units that the sums as of those dates will exceed two times the partners' cash investments as of those dates.

10. We have represented 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. We have represented that we do not believe that any market will ever exist for the sale of units and that we

will not make a market for the units. Further, the units will not be traded on an established securities market.

11. The partnership will have the objective of carrying on business for profit and dividing the gain from its operations.

12. We will not permit the purchase of units by tax-exempt investors or foreign investors.

13. We will not drill, own or operate any wells located outside the United States.

14. No partner will incur any debt that is either (a) arranged by us, the partnership, or any other person who participated in the organization or management of the partnership or the sale of partnership interests (or any person related to such persons), or (b) secured by any asset of the partnership.

The opinions of counsel 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 limited partnership agreement and to take any and all actions under the agreement in connection with the transactions contemplated by the agreement.

You should be aware that, unlike a ruling from the Service, an opinion of counsel represents only counsel's best judgment. **There can be no assurance that the Service will not successfully assert positions which are inconsistent with the opinions of counsel set forth in this discussion and Appendix D or in the tax reporting positions taken by the partners or the partnership. You should consult your own tax advisor to determine the effect of the tax issues discussed in this section and in Appendix D on your individual tax situation.**

General Tax Effects of Partnership Structure

Each partnership will be formed as a limited partnership under the limited partnership agreement and the laws of the State of West Virginia.

No tax ruling will be sought from the Service as to the status of the partnership as a partnership for federal income tax purposes.

- Any tax benefits anticipated from an investment in a partnership would be adversely affected or eliminated if the partnership is treated as a corporation for federal income tax purposes.

- While counsel has opined that the partnership will initially be treated as a partnership for federal tax purpose, that opinion is not binding on the Service.

The applicability of the federal income tax consequences described in this section depends on the treatment of the partnerships as partnerships for federal income tax purposes and not as corporations and not as associations taxable as corporations. Any tax benefits anticipated from an investment in a partnership would be adversely affected or eliminated if the partnership is treated as a corporation for federal income tax purposes.

Counsel to the partnership is of the opinion that, at the time of its formation, each of the partnerships will be treated as a partnership for federal income tax purposes. The opinion is based on the provisions of the limited partnership agreement and applicable state law and representations made by us. The opinion of counsel is not binding on the Service and is based on existing law, which is to a great extent the result of administrative and judicial interpretation. In addition, we can give no assurance that a partnership will not lose partnership status as a result of changes in the manner in which it is operated or other facts upon which the opinion of counsel is based.

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 those items in accordance with the partnership agreement and is required to take those items into account in determining the partner's income. Each partner includes those 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.

Intangible Drilling and Development Costs Deductions

Provided drilling is completed in a timely manner, investors will have the option of deducting their proportionate share of intangible drilling and development costs, which we refer to as "IDC" in 2004 for partnerships designated "PDC 2004- Limited Partnership," in 2005 for partnerships designated "PDC 2005- Limited Partnership," and in 2006 for partnerships designated "PDC 2006- Limited Partnership" or capitalizing it and deducting it over a 60-month period beginning in the month the expenditure is made.

We anticipate that 88% of subscriptions will be utilized for IDC, which, as explained below, may be deductible in the year of investment against any form of income by additional general partners or against passive income by limited partners. If so, a one unit individual investor in the maximum marginal federal income tax bracket of 35% would reduce his federal income taxes payable by $6,160. However, these IDC deductions may be subject to recapture, which could have the effect of requiring a partner to recognize additional ordinary income in later years.

Congress granted to the Treasury Secretary the authority to prescribe regulations that would allow taxpayers the option of deducting, rather than capitalizing, intangible drilling and development costs. 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 prospectus provides that approximately 88% of the investor partners' subscriptions will be utilized for IDC, which may be deductible in the year of investment. As a result, we anticipate that additional general partners will realize a deduction of approximately 88% of their investment against any form of income in the year in which the investment is made, provided wells are spudded within the first 90 days of the following year. The deduction by limited partners will be restricted to passive income. Based on an 88% deduction, a one unit ($20,000) individual investor in the maximum marginal federal income tax bracket of 35% would reduce federal income taxes payable by $6,160. The investor could also realize additional tax savings on state income taxes in many states, and self-employed investors could realize additional tax savings on self-employment taxes.

A. Classification of Costs

In general, IDCs are those costs incurred to prepare a well for production and which do not constitute the cost of a tangible asset. For example, the cost of drilling the well, grading the surface or surveying the land are IDCs. Alternatively, the cost of equipment is not an IDC because it constitutes the cost of a tangible asset. In previous partnerships sponsored by us from 1984 through 2003 (see "Prior Activities – Tax Deductions and Tax Credits of Participants in Previous Partnerships," above), intangible drilling costs have ranged from approximately 64.6% to 89.9% of the investor's 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 than or less than prior partnerships. In addition, 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. To the extent not deductible, those amounts will be included in the partnership's basis in mineral property.

B. 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, which we refer to as "AMT" (see "Alternative Minimum Tax" below).

In order for the IDC to qualify for deduction in 2004, 2005 and 2006, respectively, the wells for partnerships designated "PDC 2004- Limited Partnership," "PDC 2005- Limited Partnership," and "PDC 2006- Limited Partnership," respectively, must be spudded by March 30, 2005, 2006, and 2007, respectively. Other requirements must also be met. Although PDC will attempt to satisfy each requirement of the Service and judicial authority for deductibility of IDC in 2004, 2005, and 2006, respectively, for partnerships designated "PDC 2004- Limited Partnership," "PDC 2005- Limited Partnership," and "PDC 2006- Limited Partnership," respectively, we can give no assurance that the Service will not successfully contend that the IDC of a well which is not completed until 2005, 2006, or 2007, respectively, for partnerships designated "PDC 2004- Limited Partnership," "PDC 2005- Limited Partnership," or "PDC 2006- Limited Partnership," respectively, are not deductible in whole or in part until 2005, 2006, or 2007, respectively, for partnerships designated "PDC 2004- Limited Partnership," "PDC 2005- Limited Partnership," or "PDC 2006- Limited Partnership," respectively. Further, to the extent drilling of the partnership's wells does not commence by March 30, 2005, 2006, or 2007, respectively, for partnerships designated "PDC 2004- Limited Partnership," "PDC 2005- Limited Partnership," or "PDC 2006- Limited Partnership," respectively, the deductibility of all or a portion of the IDC may be deferred. Notwithstanding the foregoing, we can give no assurance 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 a challenge, the partners' deductions for IDC would be deferred to later years.

C. Recapture of IDC

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 may be subject to recapture, which could have the effect of requiring an investor to recognize additional ordinary income in later years . Treasury regulations provide that recapture is determined at the partner level (subject to 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. See also "Gain or Loss on Sale of Property or Units."

Depletion Deductions

- Investors generally will be entitled to claim cost depletion with respect to oil and gas properties which qualify for depletion, and investors who are entitled to percentage depletion may choose to claim the greater of cost depletion or percentage depletion.

- Investors who are independent producers (as described below) will be entitled to claim a percentage depletion deduction against their oil and gas income. The percentage depletion rate for oil and gas properties is generally 15% of the gross income generated by the property.

The owner of an economic interest in an oil and gas property is generally entitled to claim the greater of percentage depletion or cost depletion with respect to oil and gas properties which qualify for the depletion methods. Percentage depletion is generally available only with respect to the domestic oil and gas production of "independent producers." In order to qualify as an independent producer, the taxpayer, either directly or through related parties, may not be involved in the refining of more than 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 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 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 under which a deduction equal to a percentage of the taxpayer's gross income from each property is allowed in any taxable year. The allowable deduction generally is limited to 100% of the net income on a property-by-property basis, and further limited to 65% of a taxpayer's taxable income. In the case of "stripper well property," as that term is defined in Code Section 613A(c)(6)(D), the 100% of taxable income limitation has been eliminated for taxable years 1998 to 2003. Code Section 613A(c)(6)(H). Proposed legislation would extend this provision through 2004. It is anticipated that some of the properties of the partnerships will likely constitute "stripper well properties" for this purpose. Stripper wells are wells which are regarded by industry standards as being low producing wells. Generally, the term is applied to any well which produces less than 15 barrels of oil or 90 mcf per day of gas. The percentage depletion rate for oil and gas properties is generally 15% of the gross income generated by the property. However, for production from certain marginal properties, the percentage depletion rate may be increased up to 25%, depending upon the reference price for crude oil. Although this rate has not yet been published for 2005, it is anticipated to be 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 the following 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, 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.

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 the share of the adjusted basis for any depletion taken on the property, and use the adjusted basis each year in the computation of his cost depletion or in the computation of his gain or loss on the disposition of the property. These requirements may place an administrative burden on a partner.

These depletion deductions may be subject to recapture, which could have the effect of requiring an investor to recognize additional ordinary income in later years. See "Gain or Loss on Sale of Property or Units."

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. 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 the modified accelerated cost recovery system. 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. If an accelerated depreciation method is used, a portion of the depreciation will be a preference item for AMT purposes. For certain tangible property, the partnership will be allowed an additional depreciation deduction equal to 50% of the adjusted basis of the property for the year in which the property is placed in service. The adjusted basis of the property is reduced by the additional depreciation deduction before computing the amount otherwise allowable as a depreciation deduction for the tax year in which the property is placed in service and all later years. In order to be entitled to this deduction, the partnership generally must purchase the property and place it in service before January 1, 2005. You will not be able to claim depreciation deductions or the additional first-year depreciation deduction because all tangible costs have been allocated to us.

Interest Deductions

In the transaction, the investor partners will acquire their interests by remitting cash in the amount of $20,000 per unit to the partnership. In no event will the partnership accept notes in exchange for a partnership interest. Nevertheless, without any assistance from us, some investors 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 those loans, counsel is unable to express an opinion with respect to the deductibility of any interest paid or incurred on the loans.

Transaction Fees

Partnership expenditures classified as organizational expenses, and start-up expenses may be amortized over a period of not less than 60 months.

No deduction is permitted for syndication expenses, including sales commissions for the purchase of Units.

The partnership may classify a portion of the fees to be paid to third parties and to us or to the operator and its affiliates (as described in the prospectus under "Source of Funds and Use of Proceeds") as organizational expenses or other expenses that are required to be capitalized. There is no assurance that the Service will agree with, and counsel expresses 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: organizational expenses; syndication expenses; and start-up expenditures.

A partnership may elect to amortize and deduct its capitalized 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 prospectus 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 the assets.

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

The partnership intends to make payments to us, as described in greater detail in the prospectus. 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 and decrease the net loss, or increase the net income among all partners. If the Service were to successfully challenge our allocations, a partner's taxable income could be increased, resulting in increased taxes and in liability for interest and penalties.

Basis and At Risk Limitations

Partners contributing cash from "personal funds" (i.e., funds not borrowed by the partner) will not be limited, to the extent of cash contributed, in their deductibility of partnership losses by the 'at risk' basis rules or the limitations related to a partner's basis in his partnership interest.

A partner's share of partnership losses will be allowed only to the extent of the aggregate amount with respect to which the taxpayer is "at risk" for the activity at the close of the taxable year. In general, a partner is "at risk" to the extent of the amount of cash and the adjusted basis of other property contributed to the partnership. Any 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 "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 partners will purchase units by tendering cash to the partnership. To the extent the cash contributed constitutes the "personal funds" of the partners (i.e., funds not borrowed by the partner), the partners should be considered at risk with respect to those amounts. To the extent the cash contributed constitutes "personal funds," in the opinion of counsel, neither the at risk rules nor the adjusted basis rules will limit the deductibility of losses generated from the partnership. In no event, however, may a partner utilize his distributive share of partnership loss where the share exceeds the partner's basis in the partnership.

Passive Loss Limitations

A. 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." 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 the interest." 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.

A passive activity loss is the amount by which the aggregate losses from all passive activities for the taxable year exceed the aggregate income from all passive activities for the year.

Individuals and personal service corporations will be entitled to passive activity losses only to the extent of their passive income whereas closely held C corporations (other than personal service corporations) can offset passive activity losses against both passive and net active income, but not against portfolio income. In calculating passive income and loss, however, all activities of the taxpayer are aggregated. Passive activity losses 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 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 passive activity rules generally is deductible from either passive or non-passive income.

B. General Partner Interests

General partner interests will not be considered as investments in passive activities for federal tax purposes.

Additional general partners who convert to limited partner status after recording a tax loss from their investment in any year will continue to have income from the partnership treated as non-passive.

A limited partner's interest in the partnership will be considered a passive activity and losses generated while the limited partnership interest is held will be limited by the passive activity provisions. In general, an additional general partner's interest in the partnership will not be considered a passive activity, and losses generated while the general partner interest is held will not be limited by the passive activity provisions. However, if an additional general partner interest is converted to a limited partner interest prior to the spudding date, but after the end of the taxable year in which IDC was incurred, IDC will be subject to the passive activity rules. In addition, that portion of partnership income for the prior taxable year attributable to IDC treated as passive loss will be considered passive. The "spudding date" is the date that drilling commences.

If an additional general partner converts his interest to a limited partner interest under the terms of the limited partnership agreement, the character of a subsequently generated tax attribute will be dependent upon, among other things, the nature of the tax attribute and whether there arose, prior to conversion, losses to which the working interest exception applied.

If a taxpayer has any loss from any taxable year from a working interest in any oil or gas property that is treated as a non-passive loss, then any net income from the property for any succeeding taxable year is to be treated as income that is not from a passive activity. Consequently, assuming that a converting additional general partner has losses from working interests which are treated as non-passive, income from the partnership allocable to the partner after conversion would be treated as income that is not from a passive activity.

C. <u>Limited Partner Interests</u>

Income and losses of limited partners will be treated as "passive" for federal tax purposes.

If an investor partner invests in the partnership as a limited partner, his distributive share of the partnership's losses will be treated as passive activity losses, the availability of which will be limited to the partner's passive income. If the partner does not have sufficient passive income to utilize the passive activity loss, the disallowed passive activity loss will be suspended and may be carried forward to be deducted against passive income arising in future years. Further, upon the disposition of the interest to an unrelated party, in a fully taxable transaction the suspended losses will be available, as described above.

Limited partners should generally be entitled to offset their distributive shares of passive income from the partnerships with deductions from other passive activities.

<u>Conversion of Interests</u>

The partnership, in the opinion of counsel, will not be terminated solely as a result of the conversion by additional general partners of their partnership interests into limited partnership interests. For a discussion of the conversion feature of the program, see "Terms of the Offering – Conversion of Units by Additional General Partners." As discussed above under the heading "Passive Loss Limitations," an additional general partner's interest in the partnership generally will not be subject to the passive activity loss rules. If, however, an additional general partner interest is converted to a limited partner interest prior to the spudding date, but after the end of the taxable year in which IDC was incurred, IDC would be subject to the passive activity loss rules. In addition, if an additional general partner interest is converted to a limited partner interest and such converting partner previously had been allocated losses that were treated as non-passive, any future partnership net income allocated to such partner will be treated as non-passive.

Alternative Minimum Tax

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 alternative minimum tax ("AMT") liabilities with their tax advisors prior to acquiring units.

A taxpayer is subject to AMT to the extent that its "tentative minimum tax" exceeds its regular income tax liability. A corporate taxpayer's tentative minimum tax generally equals 20% of its alternative minimum taxable income ("AMTI") in excess of an exemption amount. The AMT rate for a noncorporate taxpayer is 26% or 28%, depending on the amount of its AMTI above an exemption amount. Alternative minimum taxable income is the taxpayer's regular taxable income increased by certain tax preferences and increased or decreased by certain tax adjustments. Certain items of income, deduction, gain and loss from the partnership will give rise to preferences or adjustments for AMT purposes.

Excess percentage depletion (i.e., depletion in excess of basis) is not a preference item for AMT purposes for a taxpayer other than an integrated oil company.

"Excess IDC" is generally not a preference item for AMT purposes for a taxpayer other than an integrated oil company, except to the extent that it reduces a taxpayer's AMTI by more than 40%. Excess IDC is the amount by which the taxpayer's IDC deduction exceeds the deduction that would have been allowed had IDCs been capitalized and amortized on a straight-line basis over ten years. Excess IDC is a preference, if at all, only to the extent that it exceeds 65% of the taxpayer's net income from oil and gas properties for the taxable year.

For corporations other than integrated oil companies, the adjusted current earning adjustments were repealed.

Gain or Loss on Sale of Property or Units

Sale or exchange of property by the partnership or a unit by an investor could result in ordinary income rather than capital gain. In the case of a sale or exchange of a unit, an investor could be required to recognize ordinary income greater than the amount of the gain realized on the sale. If so, the additional ordinary income would be offset by additional capital loss, but that capital loss may not be immediately deductible.

Investors who fail to report a sale or exchange of a unit in the partnership could be subject to a penalty.

An investor may recognize gain either upon the sale of his or her partnership units or from the allocation of partnership gain as a result of the partnership's sale of its property. The maximum federal income tax rate on long-term capital gains for individual taxpayers is generally 15%. Because of the recapture of IDCs and depletion, the sale may result in ordinary income to the investor, which is currently taxed at a maximum rate of 35% for individuals. If the amount of gain exceeds the amount of the deductions to be recaptured, the investor will recognize ordinary income to the extent of the recaptured deductions and capital gain for the remainder. If, upon the sale of units, the amount of deductions to be recaptured exceeds the gain realized, an investor may be required to recognize ordinary income greater than the amount of gain realized.

To balance the excess income, the investor would recognize a capital loss for the difference between the gain and the income. Depending on an investor'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 the transaction in accordance with Regulations and must attach a statement to his tax return reflecting the 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 of the information it provides to the Service to the transferor and the transferee.

Any investor who is required to notify the partnership of a transfer of his partnership interest, and, who fails to do so, may be fined $50 for each failure, limited to $100,000, provided there is no intentional disregard of the filing requirement. Similarly, the partnership may be fined for failure to report the transfer. The partnership's penalty is $50 for each failure, limited to $250,000, provided there is no intentional disregard of the filing requirement.

The tax consequences to an assignee purchaser of a unit from a partner are not described in this prospectus. Any assignor of a unit should advise his assignee to consult his own tax advisor regarding the tax consequences of the assignment.

Partnership Distributions

Under the Code, any increase in a partner's share of partnership liabilities, or any increase in the 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 the partner's individual liabilities by reason of the partnership's assumption of the individual liabilities will be considered as a distribution of money to the partner by the partnership.

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 the 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 by a distributee partner upon the disproportionate distribution to that partner of unrealized receivables or substantially appreciated inventory. The limited partnership agreement prohibits distributions to any investor partner to the extent the distributions would create or increase a deficit in the 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 limited partnership agreement.

The Service could contend that the allocations contained in the limited 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.

Tax Shelter Rules

Under federal tax law, there are various definitions of "tax shelters" and, depending upon which definition is satisfied, different obligations are required by the participants in or promoters of the tax shelter. Certain types of tax shelters must be "registered" with the Service by the organizer of the shelter. The Service assigns a tax shelter registration number to these types of shelters, and such number generally must be reported on the participants' tax returns. Another type of tax shelter (a so-called "Reportable Transaction") generally must be disclosed to the Service by the participants in the tax shelter using a Form 8886. In addition, promoters and organizers of either of these types of tax shelters generally must prepare and maintain a list of each of the participants in the tax shelter. The Service issued regulations on February 28, 2003, which define certain of these tax shelters and provide the disclosure and list maintenance requirements for these tax shelters. We believe the partnership will not be considered a tax shelter for these purposes. Accordingly, the partnership will not be required to register with the Service as a tax shelter, the partners will not be required to disclose the partnership as a tax shelter on Form 8886, and the organizers of the partnership will not be required to maintain a list of the partners as participants in a tax shelter.

Profit Motive

Investors who enter a business without economic, nontax profit motive may be denied the benefits of deductions associated with the business to the extent they exceed the income from the business.

The existence of economic, nontax motives for entering into the transaction is essential if the partners are to obtain the tax benefits associated with an investment in the partnership.

Where an activity entered into by an individual is not engaged in for profit, the individual's deductions with respect to that activity are limited to those not dependent upon the nature of the activity (e.g., interest and taxes); any remaining deductions will be limited to gross income from the activity for the year. Should it be determined that a partner's activities with respect to the transaction are "not for profit," the Service could disallow all or a portion of the deductions generated by the partnership's activities.

The Code generally provides for a presumption that an activity is entered into for profit where gross income from the activity exceeds the deductions attributable to the activity for three or more of the five consecutive taxable years ending with the taxable year in question. At the taxpayer's election, the presumption can relate to three or more of the taxable years in the 5-year period beginning with the taxable year in which the taxpayer first engages in the activity.

Due to the inherently factual nature of a partner's intent and motive in engaging in the transaction, counsel does not express an opinion as to the ultimate resolution of this issue in the event of a challenge by the Service. Partners must, however, seek to make a profit from their activities with respect to the transaction beyond any tax benefits derived from those activities or risk losing those tax benefits.

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 audit may lead to adjustments, in which event you may be required to file amended personal federal income tax returns. Any audit may also lead to an audit of your 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 the administrative proceedings and decisions, 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 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 limited partnership agreement provides for waiver of some of these rights by the investor partners. All investor partners, including those not entitled to notice, may be bound by a settlement reached by the partnership's representative "tax matters partner," which will be Petroleum Development Corporation. If a proposed tax deficiency is contested in any court by any partner of a partnership or by us, all partners of that partnership may be deemed parties to the litigation and bound by the result reached.

Consistency Requirements. You must generally treat partnership items on your federal income tax returns consistently with the treatment of the items on the partnership information return unless you file a statement with the Service identifying the inconsistency or otherwise satisfy the requirements for waiver of the consistency requirement. Failure to satisfy this requirement will result in an adjustment to conform your treatment of the item with the treatment of the item on the partnership return. Intentional or negligent disregard of the consistency requirement may subject you 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 the 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 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 position, he reasonably believed the treatment claimed was more likely than not the proper treatment of the item. A "tax shelter" item, for these purposes, 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. The definition of "tax shelter" for these purposes is different from the definitions for registration, disclosure and list maintenance purposes discussed above under "Tax Shelter Rules." A corporation is generally held to a higher standard to avoid the substantial understatement penalty attributable to tax shelter items. However, we do not believe the partnership will be considered a "tax shelter" for these purposes.

Accounting Methods and Periods

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

Social Security Benefits; Self-employment Tax

A general partner's share of any income or loss attributable to units will constitute "net earnings from self-employment" for both social security and self-employment tax purposes, while a limited partner's share of these items will not constitute "net earnings from self-employment."

State and Local Taxes

The opinions expressed in this prospectus are limited to issues of federal income tax law and do not address issues of state or local law. We urge you to consult your tax advisors regarding the impact of state and local laws on your investment in the partnership.

Individual Tax Advice Should Be Sought

We have presented only a summary of the material tax considerations that may affect your decision regarding the purchase of units. The tax considerations attendant to an investment in a partnership are complex, vary with individual circumstances, and depend in some instances upon whether the investor acquires general partner interests or limited partner interests. You should review the tax consequences with your tax advisor.

SUMMARY OF LIMITED PARTNERSHIP AGREEMENT

The limited partnership agreement in the form attached to this prospectus as Appendix A will govern your rights and obligations. You, together with your personal advisers, should carefully study the limited partnership agreement in its entirety before submitting a subscription. The following statements concerning the limited partnership agreement are merely a summary of all the material terms of the limited partnership agreement, but do not purport to be complete and in no way amend or modify the limited partnership agreement.

Responsibility of Managing General Partner

The Managing General Partner shall have the exclusive management and control of all aspects of the business of the partnership. Sections 5.01 and 6.01 of the limited partnership agreement. No investor partner shall have any voice in the day-to-day business operations of the partnership. Section 7.01. The Managing General Partner is authorized to delegate and subcontract its duties under the limited partnership agreement to others, including entities related to it. Section 5.02.

Liability of General Partners, Including Additional General Partners

General partners, including additional general partners, will have unlimited liability for partnership activities. The additional general partners will be jointly and severally liable for all obligations and liabilities to creditors and claimants, whether arising out of contract or tort, in the conduct of partnership operations. Section 7.12.

We, as operator, maintain general liability insurance. In addition, we have agreed to indemnify each of the additional general partners for obligations related to casualty and business losses which exceed available insurance coverage and partnership assets. Section 7.02.

The additional general partners, by execution of the limited partnership agreement, grant to the Managing General Partner the exclusive authority to manage the partnership business in its sole discretion and to bind the partnership and all partners in its conduct of the partnership business. The additional general partners may not participate in the management of the partnership business; and the limited partnership agreement prohibits the additional general partners from acting in a manner harmful to the assets or the business of the partnership or to do any other act which would make it impossible to carry on the ordinary business of the partnership. If an additional general partner acts contrary to the terms of the limited partnership agreement, losses caused by his or her actions will be borne by that additional general partner alone and that additional general partner may be liable to other partners for all damages resulting from his or her breach of the limited partnership agreement. Section 7.01. Additional general partners who choose to assign their units in the future may do so only as provided in the limited partnership agreement. Liability of partners who have assigned their units may continue after the assignment unless a formal assumption and release of liability is effected. Section 7.03.

Liability of Limited Partners

The West Virginia Uniform Limited Partnership Act will govern the partnerships, under which law a limited partner's liability for the obligations of the partnership is limited to his or her capital contribution, his or her share of partnership assets and the return of any part of his or her capital contribution for a period of one year after the return (or six years in the event the return is in violation of the limited partnership agreement). 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, the person takes part in the control of the business of the partnership. Section 7.01.

Allocations and Distributions

General: Profits and losses are to be allocated and cash is to be distributed in the manner described in the section entitled "Participation in Costs and Revenues." See Article III of the limited partnership agreement.

Time of Distributions: The Managing General Partner will determine and distribute not less frequently than quarterly cash available for distribution. Section 4.01. The Managing General Partner may, at its discretion, make distributions more frequently. Notwithstanding any other provision of the limited partnership agreement to the contrary, no partner will receive any distribution to the extent the distribution will create or increase a deficit in that partner's capital account (as increased by his or her share of partnership minimum gain). Section 4.03.

Liquidating Distributions: Liquidating distributions will be made in the same manner as regular distributions; however, in the event of dissolution of the partnership, distributions will be made only after due provision has been made for, among other things, payment of all partnership debts and liabilities. Section 9.03.

Voting Rights

Investor partners owning 10% or more of the then outstanding units entitled to vote have the right to require the Managing General Partner to call a meeting of the partners. Section 7.07.

Investor partners may vote with respect to partnership matters. A majority in interest of the then outstanding units entitled to vote constitutes a quorum. Each unit is entitled to one vote on all matters; each fractional unit is entitled to that fraction of one vote equal to the fractional interest in the unit. Except as otherwise provided in the limited partnership agreement, at any meeting of investor partners, approval of any matters considered at the meeting requires the affirmative vote of a majority of units represented, in person or by proxy, at the meeting at which a quorum is present. Approval of any of the following matters requires the affirmative vote of a majority of the then outstanding units entitled to vote, without the concurrence of the Managing General Partner:

The sale of all or substantially all of the assets of the partnership;

Removal of the Managing General Partner and election of a new managing general partner;

Dissolution of the partnership;

Any non-ministerial amendment to the limited partnership agreement;

Cancellation of contracts for services with the Managing General Partner or affiliates; and

The appointment of a liquidating trustee in the event the partnership is to be dissolved by reason of the retirement, dissolution, liquidation, bankruptcy, death, or adjudication of insanity or incapacity of the last remaining general partner.

Additionally, the partnership is not permitted to participate in a roll-up transaction unless the roll-up has been approved by at least 66 2/3% in interest of investor partners. Sections 5.07(m) and 7.08. The Managing General Partner if it were removed by the investor partners may elect to retain its interest in the partnership as a limited partner in the successor limited partnership (assuming that the investor partners determined to continue the partnership and elected a successor managing general partner), in which case the former Managing General Partner would be entitled to vote its interest as a limited partner. Section 7.06.

Investor partners may review the partnership's books and records and list of investor partners at any reasonable time and may copy the list of investor partners at their expense. Investor partners may submit proposals to the Managing General Partner for inclusion in the voting materials for the next meeting of investor partners for consideration by the investor partners. With respect to the merger or consolidation of the partnership or the sale of all or substantially all of the partnership's assets, investor partners may exercise dissenter's rights for fair appraisal of their units in accordance with Section 31D-13-1302 of the West Virginia Business Corporation Act. Sections 7.07, 7.08, and 8.01.

Retirement and Removal of the Managing General Partner

If the Managing General Partner desires to withdraw from the partnership for whatever reason, it may do so only upon one hundred twenty (120) days prior written notice and with the written consent of the investor partners owning a majority of the then outstanding units. Section 6.03.

If the investor partners desire to remove the Managing General Partner, they may do so at any time with the consent of the investor partners owning a majority of the then outstanding units, and upon the selection of a successor managing general partner by the investor partners owning a majority of the then outstanding units. Section 7.06.

Term and Dissolution

The partnership will continue for a maximum period ending December 31, 2055 unless earlier dissolved upon the occurrence of any of the following:

the written consent of the investor partners owning a majority of the then outstanding units;

the retirement, bankruptcy, adjudication of insanity or incapacity, withdrawal, removal, or death (or, in the case of a corporate managing general partner, the retirement, withdrawal, removal, dissolution, liquidation, or bankruptcy) of a managing general partner, unless a successor managing general partner is selected by the partners under the limited partnership agreement or the remaining managing general partner, if any, continues the partnership's business;

the sale, forfeiture, or abandonment of all or substantially all of the partnership's property; or

the occurrence of any event causing dissolution of the partnership under the laws of the State of West Virginia.

Section 9.01.

Indemnification

The Managing General Partner has agreed to indemnify each of the additional general partners for obligations related to casualty losses which exceed available insurance coverage and partnership assets. Section 7.02.

If obligations incurred by the partnership are the result of the negligence or misconduct of an additional general partner, or the violation of the terms of the limited partnership agreement by the additional general partner, then the foregoing indemnification by the Managing General Partner will be unenforceable as to that additional general partner and that additional general partner will be liable to all other partners for damages and obligations resulting from their negligence or misconduct. Section 7.02.

The Managing General Partner will be entitled to reimbursement and indemnification for all expenditures made (including amounts paid in settlement of claims) or losses or judgments suffered by it in the ordinary and proper course of the partnership's business, provided that the Managing General Partner has determined in good faith that the course of conduct which caused the loss or liability was in the best interests of the partnership, that the Managing General Partner was acting on behalf of or performing services for the partnership, and that the expenditures, losses or judgments were not the result of the negligence or misconduct on the part of the Managing General Partner. Section 6.04. The Managing General Partner will have no liability to the partnership or to any partner for any loss suffered by the partnership which arises out of any action or inaction of the Managing General Partner if the Managing General Partner, in good faith, determined that the course of conduct was in the best interest of the Partnership and the course of conduct did not constitute negligence or misconduct of the Managing General Partner. The Managing General Partner will be indemnified by the partnership to the limit of the insurance proceeds and tangible net assets of the partnership against any losses, judgments, liabilities, expenses and amounts paid in settlement of any claims sustained by it in connection with the partnership, provided that the same were not the result of negligence or misconduct on the part of the Managing General Partner.

Notwithstanding the above, the Managing General Partner will not be indemnified for liabilities arising under federal and state securities laws unless

there has been a successful adjudication on the merits of each count involving securities law violations; or

the claims have been dismissed with prejudice on their merits by a court of competent jurisdiction; or

a court of competent jurisdiction approves a settlement of the claims against a particular indemnitee and finds that indemnification of the settlement and the related costs should be made, and the court considering the request for indemnification has been advised of the position of the Securities and Exchange Commission and of the position of any state securities regulatory authority in which securities of the partnership were offered or sold as to indemnification for violations of securities laws;

provided, however, the court need only be advised of the positions of the securities regulatory authorities of those states (a) which are specifically set forth in the prospectus and (b) in which plaintiffs claim they were offered or sold partnership units.

In any claim for indemnification for federal or state securities laws violations, the party seeking indemnification must place before the court the position of the Securities and Exchange Commission, the Massachusetts Securities Division, and the Tennessee Securities Division or other respective state securities division with respect to the issue of indemnification for securities laws violations.

The partnership will not incur the cost of the portion of any insurance which insures any party against any liability as to which the party is prohibited from being indemnified. Section 6.04.

Reports to Partners

The Managing General Partner will furnish to the investor partners of each partnership semi-annual and annual reports which will contain financial statements (including a balance sheet and statements of income, partners' equity and cash flows), which statements at fiscal year end will be audited by an independent accounting firm and will include a reconciliation of the statements with information provided to the investor partners for federal income tax purposes. Financial statements furnished in a partnership's semi-annual reports will not be audited. Semi-annually, all investor partners will also receive a summary itemization of the transactions between the Managing General Partner or any affiliate and the partnership showing all items of compensation received by the Managing General Partner and its affiliates. Annually beginning with the fiscal year ended December 31, 2004 with respect to partnerships designated "PDC 2004- Limited Partnership," December 31, 2005 with respect to partnerships designated "PDC 2005- Limited Partnership," and December 31, 2006, with respect to partnerships designated "PDC 2006- Limited Partnership," oil and gas reserve estimates prepared by an independent petroleum engineer will also be furnished to the investor partners. Annual reports will be provided to the investor partners within 120 days after the close of each partnership fiscal year, and semi-annual reports will be provided within 75 days after the close of the first six months of each partnership fiscal year. In addition, the investor partners will receive on a monthly basis while the partnership is participating in the drilling and completion activities of a program, reports containing a description of the partnership's acquisition of interests in prospects, including farmins and farmouts, and the drilling, completion and abandonment of wells thereon. All investor partners will receive a report containing information necessary for the preparation of their federal income tax returns and any required state income tax returns by March 15 of each calendar year. Investor partners will also receive in the monthly reports a summary of the status of wells drilled by the partnership, the amount of oil or gas from each well and the drilling schedule for proposed wells, if known. The Managing General Partner may provide other reports and financial statements as it deems necessary or desirable. Section 8.02.

Power of Attorney

Each partner will grant to the Managing General Partner a power of attorney to execute documents deemed by the Managing General Partner to be necessary or convenient to the partnership's business or required in connection with the qualification and continuance of the partnership. Section 10.01.

Other Provisions

Other provisions of the limited partnership agreement are summarized in this prospectus under the headings "Terms of the Offering," "Source of Funds and Use of Proceeds," "Participation in Costs and Revenues," "Management," "Fiduciary Responsibility of the Managing General Partner," and "Transferability of Units." We direct the attention of prospective investors to these sections.

TRANSFERABILITY OF UNITS

Your sale of units is limited; no public market exists or will develop for the units; you may not be able to sell your units at the price or when you want.

Purchasers of units from you must satisfy the suitability requirements of this offering and as imposed by law.

No public market exists or will develop for the units. You should consider an investment in the partnerships an illiquid investment. You may not be able to sell your units when and if you want to do so and at the price you believe to be fair. In addition, as a basis of counsel's opinion that the partnerships will not be treated as "publicly traded partnerships," we have represented that the units will not be traded on an established securities market or the substantial equivalent thereof.

While units of the partnership are transferable, assignability of the units is limited, requiring among other things our consent. Section 7.03. Transfers of fractional units are prohibited, unless you own a fractional unit, in which case your entire fractional interest must be transferred. You may assign units only to a person otherwise qualified to become an investor partner, including the satisfaction of any relevant suitability requirements, as imposed by law or the partnership. See "Terms of the Offering – Investor Suitability," which presents each state's suitability requirements for investors. In no event may you make an assignment which, in the opinion of counsel to the partnership, would result in the partnership being considered to have been terminated for purposes of Section 708 of the Code, unless we consent to an assignment, or which, in the opinion of counsel to the partnership, would result in the partnership being treated as a publicly traded partnership, or which, in the opinion of counsel to the partnership, may not be effected without registration under the Securities Act of 1933, or would result in the violation of any applicable state securities laws.

A substituted additional general partner will have the same rights and responsibilities, including unlimited liability, in the partnership as every other additional general partner. Upon receipt of notice of a purported transfer or assignment of a unit of general partnership interest, we, after having determined that the purported transferee satisfies the suitability standards of an additional general partner and other conditions established by the program, will promptly notify the purported transferee of our consent to the transfer and will include with the notice a copy of the limited partnership agreement, together with a signature page. In the notification, we will advise the transferee that he or she will have the same rights and responsibilities, including unlimited liability, as every other additional general partner and that he or she will not become a partner of record until he or she returns the executed signature page to the partnership. A partnership need not recognize any assignment until the instrument of assignment has been delivered to us. The assignee of the interests has rights of ownership but may become a substituted investor partner and thus be entitled to all of the rights of an additional general partner or limited partner only upon meeting conditions, including

paying all costs and expenses incurred in connection with the substitution,

making representations to us, including satisfaction of the required suitability standards for an investment in the program, and

executing appropriate documents to evidence its agreement to be bound by all of the terms and provisions of the applicable limited partnership agreement.

Conversion of Units by the Managing General Partner and by Additional General Partners. Upon completion of drilling of a particular partnership, we will convert all units of additional general partnership interest of that partnership into units of limited partnership interest of that partnership. See "Terms of the Offering – Conversion of Units by the Managing General Partner and by Additional General Partners" for a discussion of how the conversion feature of the program works.

Unit Repurchase Program. Beginning with the third anniversary after the date of the first cash distribution of the partnership, you may request us to repurchase your units, subject to conditions. See "Terms of the Offering – Unit Repurchase Program" for a discussion of how the unit repurchase program works.

PLAN OF DISTRIBUTION

- An affiliate of the Managing General Partner is dealer manager of the offering.
- Sales will be made on a "minimum-maximum best efforts" basis through NASD-licensed broker-dealers.
- Broker-dealers will receive an amount equal to 10½% of the subscription proceeds as sales commissions, expenses, and wholesaling fees.
- Purchase of units by the Managing General Partner and/or affiliates may allow the offering to satisfy the minimum sales requirements and allow the offering to close and a partnership to be funded.
- We will not sell units to tax-exempt investors or to foreign investors.

We are offering for sale units of preformation limited and general partnership interest through our affiliate PDC Securities Incorporated, the dealer manager, and as principal distributor, and through NASD-licensed broker-dealers on a "minimum-maximum best efforts" basis for each partnership, to a select group of investors who meet the suitability standards set forth under "Terms of the Offering – Investor Suitability." We will not sell units to tax-exempt investors (including IRAs and other tax-exempt plans) or to foreign investors.

"Minimum-maximum best efforts" means that

- the various broker-dealers which will sell the units
  - will not be obligated to sell or to purchase any amount of units but

- will be obligated to make a reasonable and diligent effort (that is, their "best efforts") to sell as many units as possible and

- the offering will not close unless the minimum number of units (350 units aggregating $7 million with respect to each limited partnerships) is sold within the offering period.

The term "maximum" refers to the maximum proceeds of $70 million with respect to each limited partnerships) that can be raised with respect to any partnership.

The dealer manager, an NASD member, will receive a sales commission equal to 7% of the investor partners' subscriptions; reimbursement of bona fide accountable due diligence expenses of up to ½% of the investor partners' subscriptions; and wholesaling fees and expenses, meeting costs, and marketing fees and expenses and other compensation equal to 3% of the investor partners' subscriptions, for an aggregate of $7,350,000 for the sale of the maximum number of 3,500 units of a limited partnership. The dealer manager may reallow these commissions, expenses and fees, in whole or in part, to NASD-licensed broker-dealers for sale of the units. The dealer manager will retain, in lieu of reimbursement of specific expenses, 2% of investor partners' subscriptions for wholesaling fees and expenses, meeting costs and other selling expenses. In no event will the total compensation paid to NASD members exceed 10½% of subscriptions (comprised of 7% in sales commissions, 3% in wholesaling fees and expenses, marketing fees and expenses and other compensation and ½% of subscriptions for reimbursement of bona fide accountable due diligence expenses). Any commissions and other remuneration will be paid in cash solely on the amount of initial subscriptions and only as permitted under federal and state securities laws and applicable rules and regulations. As provided in the soliciting dealers agreements between PDC Securities Incorporated and the various soliciting dealers, we, prior to the time that we have received the minimum required subscriptions in cleared funds from subscribers that are suitable to be investor partners in the partnership in which units are then being offered, may advance to the various NASD-licensed broker-dealers from our own funds the sales commissions and due diligence expenses which would otherwise be payable in connection with the subscriptions prior to the close and funding of the partnership. If the sale of the minimum number of units has not occurred as of the time as the particular offering terminates or we determine not to organize and fund the partnership for any reason, those broker-dealers which have received commissions and due diligence expenses in advance from us with respect to the sale of units in that partnership are required by the soliciting-dealers agreements to return the commissions and due diligence expenses to us promptly.

To help assure an orderly market for the partnership units, the Managing General Partner, the dealer manager, and the selling dealers may utilize such methods as they deem appropriate to allocate units among interested investors, if they anticipate that demand for units will exceed the available supply, provided that no changes to compensation may be made. These methods may include, but will not be limited to, allocations to selling dealers, brokers, or investors; priority acceptance for previous investors; priority treatment for investors rejected from or declined by earlier partnerships due to inadequate units availability; or such other methods as may be approved by the Managing General Partner.

No sales commissions will be paid on sales of units to officers, directors, employees, or registered representatives of a soliciting dealer if the soliciting dealer, in its discretion, has elected to waive the sales commissions. Any units so purchased will be held for investment and not for resale.

We, the dealer manager, and soliciting dealers have agreed to indemnify one another against civil liabilities, including liability under the Securities Act of 1933. In the opinion of the Securities and Exchange Commission, indemnification for liabilities under the Securities Act is against public policy as expressed in the Securities Act and is therefore unenforceable. Members of the selling group may be deemed to be "underwriters" as defined under the Securities Act, and their commissions and other payments may be deemed to be underwriting compensation.

The dealer manager may offer the units and receive commissions in connection with the sale of units only in those states in which it is lawfully qualified to do so.

We and our affiliates may elect to purchase units in the offering on the same terms and conditions as other investors, net of commissions. The purchase of units by us and/or our affiliates may have the effect of allowing the offering to be subscribed to the minimum, resulting in satisfaction of an express condition of the offering, and thus allow the offering to close. We and/or our affiliates will not purchase more than 10% of the units subscribed by the investor partners in any partnership. Additionally, not more than $50,000 of units purchased by us and affiliates are permitted to be applied to satisfying the minimum requirement. Any units purchased by us and/or our affiliates will be held for investment and not for resale.

Subscription Process

We are offering up to $70 million of units in the partnership to the public through the dealer manager and soliciting dealers. The agreement between the dealer manager and the soliciting dealers requires the soliciting dealers to make diligent inquiries of you in order to determine whether your purchase of units is suitable for you, and to transmit promptly to us the completed subscription documentation and any support documentation we may reasonably require. The dealer manager or a soliciting dealer is also required to deliver to you a copy of this prospectus.

We are offering and selling the units subject to our acceptance of your subscription. We have the unconditional right to accept or reject your subscription within 30 days after our receipt of a fully completed subscription agreement and payment for the number of units subscribed for. If we accept your subscription, we will mail you a confirmation shortly after our acceptance. We may not complete any sale of units until at least five business days after the date you receive this prospectus. If we reject your subscription, we will return to you your subscription funds, without interest or deduction.

Representations and Warranties in the Subscription Agreement

The subscription agreement requires you to make the following factual representations:

> Your tax identification number set forth in the subscription agreement is accurate and you are not subject to backup withholding;
>
> You received a copy of this prospectus not less than five business days prior to your signing the subscription agreement;
>
> You meet the minimum income, net worth and any other applicable suitability standards established for you, as described in "Investor Suitability," which appears earlier in this prospectus;
>
> You are purchasing units for your own account; and
>
> If a fiduciary, you are purchasing for a person or entity having the appropriate income, net worth and any other applicable suitability standards specified in "Investor Suitability."

Each of the above representations is included in the subscription agreement in order to help satisfy our responsibility to make every reasonable effort to determine that the purchase of units is a suitable and appropriate investment for you and that appropriate income tax reporting information is obtained. We will not sell any units to you unless you are able to make the above factual representations by executing the subscription agreement.

By executing the subscription agreement, you will not be waiving any rights under the federal securities laws.

Determination of Your Suitability as an Investor

We, the dealer manager and each soliciting dealer will make reasonable efforts to determine that you satisfy the suitability standards set forth under "Investor Suitability" and that an investment in the units is an appropriate investment for you. The soliciting dealers must determine whether you can reasonably benefit from this investment. In making this determination, the soliciting dealers will consider whether:

> You have the capability of understanding fundamental aspects of our business based on your employment experience, education, access to advice from qualified sources such as attorneys, accountants and tax advisors, and your prior experience with investments of a similar nature;
>
> You have an apparent understanding of:
>
> > The fundamental risks and possible financial hazards of this type of investment;
> >
> > The fact that no market for the units will develop and that your units cannot be readily sold; and
> >
> > The tax consequences of your investment. and
>
> You have the financial capability to invest in the units.

By executing the subscription agreement, each soliciting dealer acknowledges its determination that the units constitute a suitable investment for you. Each soliciting dealer is required to represent and warrant that it has complied with all applicable laws in determining the suitability of the units as an investment for you.

SALES LITERATURE

In connection with the offering, the NASD-registered broker-dealers may utilize various sales literature which discusses aspects of the program, namely, a program highlight information piece which will constitute the prospectus summary ("Program Summary" in bullet format), an introduction to the program ("Flip Chart/Slide Presentation"), and prospect letters ("Broker-Dealer Guide"). The program may also utilize a program general summary piece ("Program Summary" in text format), a sheet presenting information regarding comparative investment deductions ("Investment Deductions"), and a Web site at www.pdcgas.com. Our sales material will not contain any material information which is not also set forth in the prospectus. The offering of units will be made only by means of this prospectus.

LEGAL OPINIONS

The validity of the units offered by this prospectus and federal income tax matters discussed under "Tax Considerations" and in the tax opinion set forth in Appendix D to the prospectus have been passed upon by Duane Morris LLP, 1667 K Street, N.W., Washington, D.C. 20006.

EXPERTS

The Partnership reserves and future net revenues information presented for nine of the partnerships as footnoted in the table "Partnership Estimated Proved Reserves and Future Net Revenues" which appears above under the caption "Prior Activities" and in Note 17 to the audited financial statements of Petroleum Development Corporation included in this prospectus has been prepared by Wright & Company, Inc., Brentwood, Tennessee, independent petroleum consultants.

The consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2004 and 2003, have been included in this prospectus and in the registration statement in reliance upon the report of KPMG LLP, independent registered public accounting firm, appearing elsewhere in the registration statement, and upon the authority of said firm as experts in accounting and auditing. KPMG's report covering the December 31, 2003 consolidated balance sheet referred to a change in accounting for asset retirement obligations.

ADDITIONAL INFORMATION

A registration statement on Form S-1 (Reg. No. 333-111,260) with respect to the units offered by this prospectus has been filed on behalf of the partnerships with the Securities and Exchange Commission, Washington, D.C. 20549, under the Securities Act of 1933. This prospectus does not contain all of the information set forth in the registration statement, portions of which have been omitted under the rules and regulations of the Securities and Exchange Commission. Reference is made to the registration statement, including exhibits, for further information. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. This registration statement, as well as all exhibits and amendments, has been filed and will be filed electronically with the Commission through the Electronic Data Gathering, Analysis, and Retrieval ("EDGAR") system. The registration statement and all exhibits and amendments thereto are publicly available through the Commission's Web site (http://www.sec.gov). We hereby make reference to the copy of documents filed as exhibits to the Registration Statement for full statements of the provisions of those documents, and we qualify each statement in this prospectus in all respects by this reference. You may obtain copies of any materials filed as a part of the registration statement from the Securities and Exchange Commission by payment of the requisite fees for materials or you may examine these documents in the offices of the Commission without charge or by downloading the documents from the SEC's EDGAR system. The delivery of this prospectus at any time does not imply that the information contained in this prospectus is correct as of any time subsequent to the date of this prospectus.

GLOSSARY OF TERMS

The following terms used in this prospectus shall unless the context otherwise requires have the following respective meanings:

Additional General Partners: Those investor partners who purchase units as additional general partners, and their transferees and assigns.

Administrative Costs: All customary and routine expenses incurred by the Managing General Partner for the conduct of program administration, including legal, finance, accounting, secretarial, travel, office rent, telephone, data processing and other items of a similar nature.

Affiliate: An affiliate of a specified person means (a) any person directly or indirectly owning, controlling, or holding with power to vote 10 percent or more of the outstanding voting securities of the specified person; (b) any person 10 percent or more of whose outstanding voting securities are directly or indirectly owned, controlled, or held with power to vote, by the specified person; (c) any person directly or indirectly controlling, controlled by, or under common control with the specified person; (d) any officer, director, trustee or partner of the specified person; and (e) if the specified person is an officer, director, trustee or partner, any person for which the person acts in any capacity.

Assessment: Additional amounts of capital which may be mandatorily required of or paid voluntarily by an investor partner beyond his subscription commitment.

Capital Accounts: The accounts to be maintained for each partner on the books and records of the partnership under Section 3.01 of the limited partnership agreement.

Capital Available for Investment: The sum of (a) the subscriptions, net of the sales commissions, due diligence expenses, marketing support fees and other compensation, and wholesaling fees, which aggregate 10½% of subscriptions, and the management fee and (b) the capital contribution of the Managing General Partner.

Capital Contribution: With respect to each investor partner, the total investment, including the original investment, assessments and amounts reinvested, by the investor partner to the capital of the partnership under Section 2.02 of the limited partnership agreement and, with respect to the Managing General Partner and initial limited partner, the total investment, including the original investment, assessments and amounts reinvested, to the capital of the partnership under Section 2.01 of the limited partnership agreement.

Capital Expenditures: Those costs associated with property acquisition and the drilling and completion of oil and gas wells which are generally accepted as capital expenditures under the provisions of the Internal Revenue Code.

Carried Interest: An equity interest in a program issued to a person without consideration, in the form of cash or tangible property, in an amount proportionately equivalent to that received from the participants.

Code: The Internal Revenue Code of 1986, as amended.

Cost: When used with respect to the sale of property to the partnership, means (a) the sum of the prices paid by the seller to an unaffiliated person for the property, including bonuses; (b) title insurance or examination costs, brokers' commissions, filing fees, recording costs, transfer taxes, if any, and like charges in connection with the acquisition of the property; (c) a pro rata portion of the seller's actual necessary and reasonable expenses for seismic and geophysical services; and (d) rentals and ad valorem taxes paid by the seller with respect to the property to the date of its transfer to the buyer, interest and points actually incurred on funds used to acquire or maintain the property, and the portion of the seller's reasonable, necessary and actual expenses for geological, engineering, drafting, accounting, legal and other like services allocated to the property cost in conformity with generally accepted accounting principles and industry standards, 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 expenses enumerated in this subsection (d) hereof shall have been incurred not more than 36 months prior to the purchase by the partnership; provided that the period may be extended, at the discretion of the state securities administrator, upon proper justification. When used with respect to services, "cost" means the reasonable, necessary and actual expense incurred by the seller on behalf of the partnership in providing the services, determined in accordance with generally accepted accounting principles. As used elsewhere, "cost" means the price paid by the seller in an arm's-length transaction.

Dealer Manager: PDC Securities Incorporated, our affiliate.

Development Well: A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Direct Costs: All actual and necessary costs directly incurred for the benefit of the partnership and generally attributable to the goods and services provided to the partnership by parties other than the Managing General Partner or its affiliates. Direct costs shall not include any cost otherwise classified as organization and offering expenses, administrative costs, operating costs or property costs. Direct costs may include the cost of services provided by the Managing General Partner or its affiliates if the services are provided by written contracts and in compliance with Section 5.07(e) of the limited partnership agreement.

Distributable Cash: Cash remaining for distribution to the Managing General Partner and the investor partners after the payment of all partnership obligations, including debt service and the establishment of contingency reserves for anticipated future costs as determined by the Managing General Partner.

Drilling and Completion Costs: All costs, excluding operating costs, of drilling, completing, testing, equipping and bringing a well into production or plugging and abandoning it, including all labor and other construction and installation costs incident thereto, location and surface damages, cementing, drilling mud and chemicals, drillstem tests and core analysis, engineering and well site geological expenses, electric logs, costs of plugging back, deepening, rework operations, repairing or performing remedial work of any type, costs of plugging and abandoning any well participated in by the Partnership, and reimbursements and compensation to well operators, including charges paid to the Managing General Partner as unit operator during the drilling and completion phase of a well, plus the cost of the gathering systems and of acquiring leasehold interests.

Dry Hole: Any well abandoned without having produced oil or gas in commercial quantities.

Escrow Agent: Branch Banking and Trust Company, Wilson, North Carolina, or its successor.

Exploratory Well: A well drilled to find commercially productive hydrocarbons in an unproved area, to find a new commercially productive horizon in a field previously found to be productive of hydrocarbons at another horizon, or to significantly extend a known prospect.

Farmout: An agreement in which the owner of a leasehold or working interest agrees to assign an interest in specific acreage to the assignees, retaining an interest such as an overriding royalty interest, an oil and gas payment, offset acreage or other type of interest, subject to the drilling of one or more specific wells or other performance as a condition of the assignment.

Future Net Revenues: Estimated future cash in-flow from oil and natural gas sales of partnership estimated proved reserves as estimated by the petroleum engineers less estimated future production and development costs. Oil and natural gas sales assume oil and natural gas prices remain constant at the current price at the date of the reserve report. Production and development costs are derived based on current cost levels and assume continuation of current economic conditions.

Horizon: A zone of a particular formation; that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.

IDC: Intangible drilling and development costs.

Independent Expert: A person with no material relationship to the Managing General Partner who is qualified and who is in the business of rendering opinions regarding the value of oil and gas properties based upon the evaluation of all pertinent economic, financial, geologic and engineering information available to the Managing General Partner.

Initial Limited Partner: Steven R. Williams or any successor to his interest.

Investor Partner: Any investor participating in the partnership as an Additional General Partner or a limited partner, but excluding the Managing General Partner and initial limited partner.

Landowners' Royalty Interest: An interest in production, or the proceeds therefrom, to be received free and clear of all costs of development, operation, or maintenance, reserved by a landowner upon the creation of an oil and gas lease.

Lease: Full or partial interests in: (a) undeveloped oil and gas leases; (b) oil and gas mineral rights; (c) licenses; (d) concessions; (e) contracts; (f) fee rights; or (g) other rights authorizing the owner thereof to drill for, reduce to possession and produce oil and gas.

Limited Partners: Those investor partners who purchase units as limited partners, transferees or assignees who become limited partners, or additional general partners whose interests are converted to limited partnership interests under the provisions of the limited partnership agreement.

Limited Partnership Agreement: The limited partnership agreement as it may be amended from time to time, the form of which is attached to the prospectus as Appendix A.

Loss: The excess of the partnership's losses and deductions over the partnership's income and gains, computed in accordance with the provisions of the federal income tax laws.

Management Fee: The fee to which the Managing General Partner is entitled under Section 6.06 of the limited partnership agreement.

Managing General Partner: Petroleum Development Corporation or its successors.

Mcf: One thousand cubic feet of natural gas measured at the standard temperature of 60° Fahrenheit and pressure of 14.65 psi.

Net Subscriptions: An amount equal to total subscriptions of the investor partners less the amount of organization and offering costs of the partnership.

Net Well: The sum of fractional working interests owned and drilled by the partnership.

Non-Capital Expenditures: Those expenditures associated with property acquisition and the drilling and completion of oil and gas wells that under present law are generally accepted as fully deductible currently for federal income tax purposes.

Offering Termination Date: December 31, 2004 with respect to partnerships designated "PDC 2004- Limited Partnership," December 30, 2005 with respect to partnerships designated "PDC 2005- Limited Partnership," and December 29, 2006 with respect to partnerships designated "PDC 2006- Limited Partnership" or the earlier date as the Managing General Partner, in its sole and absolute discretion, shall select.

Oil and Gas Interest: Any oil or gas royalty or lease, or fractional interest therein, or certificate of interest or participation or investment contract relative to the royalties, leases or fractional interests, or any other interest or right which permits the exploration of, drilling for, or production of oil and gas or other related hydrocarbons or the receipt of the production or the proceeds thereof.

Operating Costs: Expenditures made and costs incurred in producing and marketing oil or gas from completed wells, including, in addition to labor, fuel, repairs, hauling, materials, supplies, utility charges and other costs incident to or therefrom, ad valorem and severance taxes, insurance and casualty loss expense, and compensation to well operators or others for services rendered in conducting the operations.

Organization and Offering Costs: All costs of organizing and selling the offering including, but not limited to, total underwriting and brokerage discounts and commissions (including fees of the underwriters' attorneys), expenses for printing, engraving, mailing, salaries of employees while engaged in sales activity, charges of transfer agents, registrars, trustees, escrow holders, depositaries, engineers and other experts, expenses of qualification of the sale of the securities under federal and state law, including taxes and fees, accountants' and attorneys' fees and other front end fees.

Overriding Royalty Interest: An interest in the oil and gas produced under a specified oil and gas lease or leases, or the proceeds from the sale thereof, carved out of the working interest, to be received free and clear of all costs of development, operation, or maintenance.

Participant: The purchaser of a unit in the program.

Partners: The Managing General Partner, the additional general partners other than the Managing General Partner, and the limited partners. Reference to a "partner" shall mean any one of the partners.

Partnership or Partnerships: One or all of the limited partnerships to be formed in the PDC 2004-2006 Drilling Program comprised of a series of up to twelve limited partnerships to be designated as the PDC 2004-A Limited Partnership, the PDC 2004-B Limited Partnership, the PDC 2004-C Limited Partnership, PDC 2004-D Limited Partnership, PDC 2005-A Limited Partnership, PDC 2005-B Limited Partnership, PDC 2005-C Limited Partnership, PDC 2005-D Limited Partnership, PDC 2006-A Limited Partnership, PDC 2006-B Limited Partnership, PDC 2006-C Limited Partnership, and PDC 2006-D Limited Partnership. The partnerships will be governed by the West Virginia Uniform Limited Partnership Act.

Together the partnerships, for purposes of this offering, are referred to as the PDC 2004-2006 Drilling Program or sometimes as the program.

Partnership Minimum Gain: Partnership minimum gain as defined in Treas. Reg. Section 1.704-2(d)(1).

PDC: Petroleum Development Corporation.

Profit: The excess of the partnership's income and gains over the partnership's losses and deductions, computed in accordance with the provisions of the federal income tax laws.

Program: One or more limited partnerships formed, or to be formed, for the primary purpose of exploring for oil or gas. In this prospectus, PDC 2004-2006 Drilling Program.

Prospect: A contiguous oil and gas leasehold estate, or lesser interest therein, upon which drilling operations may be conducted. In general, a prospect is an area in which a partnership owns or intends to own one or more oil and gas interests, which is geographically defined on the basis of geological data by the Managing General Partner and which is reasonably anticipated by the Managing General Partner to contain at least one reservoir. An area covering lands which are believed by the Managing General Partner to contain subsurface structural or stratigraphic conditions making it susceptible to the accumulations of hydrocarbons in commercially productive quantities at one or more horizons. The area, which may be different for different horizons, shall be designated by the Managing General Partner in writing prior to the conduct of program operations and shall be enlarged or contracted from time to time on the basis of subsequently acquired information to define the anticipated limits of the associated hydrocarbon reserves and to include all acreage encompassed therein. A "prospect" with respect to a particular horizon may be limited to the minimum area permitted by state law or local practice, whichever is applicable, to protect against drainage from adjacent wells if the well to be drilled by the partnership is to a horizon containing proved reserves.

Prospectus: The partnership's prospectus, including a preliminary prospectus, of which the limited partnership agreement is a part, under which the units are being offered and sold.

Proved Developed Oil and Gas Reserves: 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 Oil and Gas Reserves: Proved oil and gas reserves 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.

i. 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 (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) 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.

ii. 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.

iii. Estimates or proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves; (B) 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; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.

Proved Undeveloped Reserves: 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 the techniques have been proved effective by actual tests in the area and in the same reservoir.

Recompletion: A second completion of the same zone in a well performed several years after the initial completion with objectives of restoring the well to near the original production rate and increasing the recoverable reserves of the well.

Reservoir: A separate structural or stratigraphic trap containing an accumulation of oil or gas.

Roll-Up: A transaction involving the acquisition, merger, conversion, or consolidation, either directly or indirectly, of the partnership and the issuance of securities of a roll-up entity. The term does not include:

1. a transaction involving securities of the partnership that have been listed for at least 12 months on a national exchange or traded through the National Association of Securities Dealers Automated Quotation National Market System; or

2. a transaction involving the conversion to corporate, trust or association form of only the partnership if, as a consequence of the transaction, there will be no significant adverse change in any of the following:

    a. voting rights;

    b. the term of existence of the partnership;

    c. sponsor compensation; or

    d. the partnership's investment objectives.

Roll-Up Entity: A partnership, trust, corporation or other entity that would be created or survive after the successful completion of a proposed roll-up transaction.

Royalty: A fractional undivided interest in the production of oil and gas wells, or the proceeds therefrom to be received free and clear of all costs of development, operations or maintenance. Royalties may be reserved by landowners upon the creation of an oil and gas lease ("landowner's royalty") or subsequently carved out of a working interest ("overriding royalty").

Securities Act: Securities Act of 1933, as amended.

Sponsor: Any person directly or indirectly instrumental in organizing, wholly or in part, a program or any person who will manage or is entitled to manage or participate in the management or control of a program. "Sponsor" includes the managing and controlling general partner(s) and any other person who actually controls or selects the person who controls 25% or more of the exploratory, developmental or producing activities of the partnership, or any segment thereof, even if that person has not entered into a contract at the time of formation of the partnership. "Sponsor" does not include wholly independent third parties such as attorneys, accountants, and underwriters whose only compensation is for professional services rendered in connection with the offering of units. Whenever the context of these guidelines so requires, the term "sponsor" shall be deemed to include its affiliates.

Spudding Date: The date that drilling commences.

Subscriptions: The subscription agreement(s) or the amount indicated on the subscriptions agreements that the additional general partners and the limited partners have agreed to pay to a partnership.

Tangible Costs: Those costs which are generally accepted as capital expenditures under the provisions of the Code.

Treas. Reg.: A regulation promulgated by the Treasury Department under Title 26 of the United States Code.

Unit: An undivided interest of an investor partner in the aggregate interest in the capital and profits of the partnership.

Well Head Gas Price: The price paid by a gas purchaser for gas produced from partnership wells excluding any tax reimbursements or transportation allowances.

West Virginia Act: The West Virginia Uniform Limited Partnership Act.

Wholesaling Fee: A fee paid to a representative of the dealer manager who helps introduce and explain the program to registered representatives with firms executing a selling agreement with the dealer manager for the program.

Working Interest: An interest in an oil and gas leasehold which is subject to some portion of the costs of development, operation, or maintenance.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
March 31, 2005 and December 31, 2004

Assets	2005 (Unaudited)	2004
Current assets:		
Cash and cash equivalents	$94,629,100	$ 77,735,300
Accounts and notes receivable	29,931,700	33,902,800
Inventories.	3,837,600	1,657,300
Prepaid expenses	_3,861,200	_7,334,200
Total current assets	132,259,600	120,629,600
Properties and equipment	328,230,100	308,348,200
Less accumulated depreciation, depletion, and amortization		_88,341,300
	_93,144,200	
	235,085,900	220,006,900
Other assets	___729,300	__756,500
	$368,074,800	$341,393,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued expenses	$70,355,300	$ 65,756,800
Advances for future drilling contracts	54,421,100	42,497,300
Funds held for future distribution	15,404,400	_12,911,800
Total current liabilities	140,180,800	121,165,900
Long-term debt	18,000,000	21,000,000
Other liabilities	5,071,700	3,927,500
Deferred income taxes	30,209,300	29,843,200
Asset retirement obligation	794,600	783,500
Stockholders' equity:		
Common stock	165,800	165,800
Additional paid-in capital	36,919,500	36,802,300
Retained earnings	143,447,600	130,109,800
Accumulated other comprehensive income	_(6,714,500)	_(2,405,000)
Total stockholders' equity	173,818,400	_164,672,900
	$368,074,800	$341,393,000

AN INVESTOR IN PDC 2004-2006 DRILLING PROGRAM DOES NOT THEREBY ACQUIRE ANY
INTEREST IN THE ASSETS OF PETROLEUM DEVELOPMENT CORPORATION

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

1. **Accounting Policies**
Reference is hereby made to the Company's audited Consolidated Balance Sheet at December 31, 2004 which contains a summary of significant accounting policies followed by the Company in preparation of its consolidated financial statements. These policies were also followed in preparing the unaudited balance sheet at March 31, 2005 included herein.

2. **Basis of Presentation**
The Management of the Company believes that all adjustments (consisting of only normal recurring accruals) necessary to a fair statement of the financial position of the Company as of March 31, 2005 have been made.

3. **Oil and Gas Properties**
Oil and Gas Properties are reported on the successful efforts method.

4. **Contingencies and Commitments**
There are no material loss contingencies at March 31, 2005. There has been no change in commitments and contingencies as described in Note 8 of the Consolidated Balance Sheet at December 31, 2004.

The Company drilled one exploratory well in 2004 (Fox Federal #1-13) and drilled another one in the first quarter of 2005 (Coffeepot Springs #24-34). The Fox Federal #1-13 has been completed and testing was underway, however, the well has not been classified as successful or dry. Testing of this well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing late in the second quarter of 2005. The cost of this well as of April 30, 2005 is $4.5 million. The Coffeepot Springs #24-34 has been drilled to total depth and is scheduled to be fractured in the next few weeks and has not been classified as successful or dry. The cost of this well as of April 30, 2005 is $2.6 million. If either of these wells is determined to be a dry hole, its cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting.

5. **Business Segments (Thousands)**

PDC's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also engages in oil and gas sales to residential, commercial and industrial end-users. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for March 31, 2005 and December 31, 2004 is as follows:

	March 31, 2005	December 31, 200
SEGMENT ASSETS		
Drilling and Development	$65,239	64,348
Natural Gas Marketing	24,524	28,689
Oil and Gas Sales	252,432	221,516
Well Operations	18,996	16,518
Unallocated amounts		
Cash	33	112
Other	6,851	10,210
Total	$368,075	341,393

AN INVESTOR IN PDC 2004-2006 DRILLING PROGRAM DOES NOT THEREBY ACQUIRE ANY

INTEREST IN THE ASSETS OF PETROLEUM DEVELOPMENT CORPORATION

6. **Sales of Undeveloped Acreage**

On January 28, 2005 the Company sold a portion of one of its undeveloped Garfield County, Colorado leases to an unaffiliated entity. The proceeds of the sale were $6.2 million and the Company's carrying value of the property was zero. The Company is required to remit $1.0 million to the original lessor, unless it constructs certain facilities adjacent to this undeveloped property subject to certain timing conditions. The Company at this time cannot determine if it will be able to comply with this provision, therefore a $1.0 million accrual has been established and the pre-tax gain on the sale was reduced to $5.2 million. This gain has been included in "Other Income" in the accompanying income statement and amounted to an after-tax effect on Earnings Per Share of $.20.

7. **Comprehensive income**

Comprehensive income includes certain items recorded directly to shareholders' equity and classified as other comprehensive income. The following table illustrates the calculation of comprehensive income for the quarter ended March 31, 2005.

Net Income	$13,337,800
Reclassification adjustment for settled contracts included in net income (net of tax of $744,500)	1,169,400
Change in fair value of outstanding hedging positions (net of tax of $900,000)	(5,478,900)
Other Comprehensive Income (loss)	(4,309,500)
Comprehensive Income	$9,028,300

8. **Common Stock Repurchase**

At a meeting held on Friday, March 18, 2005, the Board of Directors of Petroleum Development Corporation approved a stock repurchase plan to allow the Company to repurchase up to 2% of the Company's common stock in 2005. The Company intends at a minimum to purchase adequate shares to insure no dilution from employee stock compensation plans and may also make open market purchases from time to time.

9. **Subsequent Events**

On April 27, 2005, the Company completed the sale to an unaffiliated entity of 111 Pennsylvania wells it purchased from Pemco Gas, Inc. in 1998. The Company received proceeds of $3.4 million and will record a gain of approximately $1.1 million in the second quarter of 2005. The transaction was effective April 1, 2005.

As of June 2005, tests have been completed and the results evaluated on Fox Federal #1-13, one of our exploratory wells. (Refer to Note 4). The test results indicate that the well is not commercial, and will be plugged and abandoned. Under the Successful Efforts Method of Accounting, exploratory well costs must be expensed in the period when the well is deemed to be dry. The total well costs for the Fox Federal #1-13 including estimated plugging costs is approximately $4.9 million.

AN INVESTOR IN PDC 2004-2006 DRILLING PROGRAM DOES NOT THEREBY ACQUIRE ANY INTEREST IN THE ASSETS OF PETROLEUM DEVELOPMENT CORPORATION

New Accounting Standards

The FASB issued FIN 46, "Consolidation of Variable Interest Entities", in January 2003 and amended the interpretation in December 2003. A variable interest entity (VIE) is an entity in which its voting equity investors lack the characteristics of having a controlling financial interest or where the existing capital at risk is insufficient to permit the entity to finance its activities without receiving additional financial support from other parties. FIN 46 requires the consolidation of entities which are determined to be VIEs when the reporting company determines itself to be the primary beneficiary (the entity that will absorb a majority of the VIE's expected losses, receive a majority of the VIE's residual returns, or both). The amended interpretation was effective for the first interim or annual reporting period ending after March 15, 2004, with the exception of special purpose entities for which the statement was effective for periods ending after December 15, 2003. We have completed a review of our partnership investments and have determined that those entities do not qualify as VIEs.

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), "Share-Based Payment" which is a revision of FASB Statement No. 123, "Accounting for Stock-Based Compensation". Statement 123R supercedes APB opinion No. 25, "Accounting for Stock Issued to Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The provisions of this statement becomes effective for our first quarter 2006. Management has not determined the impact that this statement will have on our consolidated financial statements.

Recently Issued Accounting Pronouncements

Asset Retirement Obligations

On March 30, 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN No. 47). This interpretation clarifies that the term "conditional asset retirement obligation" as used in Statement No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity incurring the obligation. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability, rather than the timing of recognition of the liability, when sufficient information exists. FIN No. 47 will be effective for the Company at the end of the fiscal year ended December 31, 2005. The Company has not determined the impact on the Company's financial position or results of operations of the application of FIN No. 47.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1 "Accounting for Suspended Well Costs." This staff position amends FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies which use the successful efforts method of accounting. The position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the FSP requires annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. The guidance in the FSP is required to be applied to the first reporting period beginning after April 4, 2005 on a prospective basis to existing and newly capitalized exploratory well costs. The Company does not expect the application of this FSP to have a significant impact on the Company's financial position or results of operations.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31, 2004 and 2003

(With Report of Independent Registered Public Accounting Firm Thereon)

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Petroleum Development Corporation:

We have audited the consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2004 and 2003. These consolidated balance sheets are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated balance sheets based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated balance sheets are free of material misstatement. An audit of the consolidated balance sheets includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated balance sheets. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated balance sheets referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 2004 and 2003, in conformity with U. S. generally accepted accounting principles.

As discussed in note 1 to the consolidated balance sheets, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, in 2003.

KPMG LLP

Pittsburgh, Pennsylvania

March 30, 2005

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2004 and 2003

Assets	2004	2003
Current assets:		
Cash and cash equivalents	$77,070,400	78,512,900
Restricted cash	664,900	1,866,400
Notes and accounts receivable	33,902,800	23,067,000
Inventories	1,657,300	2,014,300
Prepaid expenses	7,334,200	5,907,000
Total current assets	120,629,600	111,367,600
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	291,436,700	251,558,900
Pipelines	9,515,000	9,097,000
Transportation and other equipment	4,453,700	3,460,900
Land and buildings	2,942,800	1,747,500
	308,348,200	265,864,300
Less accumulated depreciation, depletion and amortization	88,341,300	71,182,100
	220,006,900	194,682,200
Other assets	756,500	672,200
	$341,393,000	306,722,000

Liabilities and Stockholders' Equity

	2004	2003
Current liabilities:		
Accounts payable	$42,438,400	29,453,000
Other accrued expenses	23,318,400	16,814,200
Advances for future drilling contracts	42,497,300	50,458,800
Funds held for future distribution	12,911,800	8,410,900
Total current liabilities	121,165,900	105,136,900
Long-term debt	21,000,000	53,000,000
Other liabilities	3,927,500	2,449,100
Deferred income taxes	29,843,200	21,800,200
Asset retirement obligation	783,500	731,200
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 16,589,324 and 15,628,433 shares	165,800	156,200
Additional paid-in capital	36,802,300	28,578,100
Retained earnings	130,109,800	96,049,200
Accumulated other comprehensive loss, net of tax	(2,405,000)	(1,178,900)
Total stockholders' equity	164,672,900	123,604,600
	$341,393,000	306,722,000

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Petroleum Development Corporation (PDC) and its wholly owned subsidiaries, Riley Natural Gas (RNG) and PDC Securities Incorporated. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in limited partnerships under the proportionate consolidation method. Under this method, the Company's balance sheets include its prorata share of assets and liabilities, respectively, of the limited partnerships in which it participates.

The Company is involved in four business segments. The segments are drilling and development, natural gas marketing, oil and gas sales and well operations. (See Note 15)

The Company grants credit to purchasers of oil and gas and the owners of managed properties, substantially all of whom are located in West Virginia, Tennessee, Pennsylvania, Michigan, North Dakota, Colorado and Kansas.

Cash Equivalents

The Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

Restricted Cash

The Company is required to maintain margin deposits with brokers for outstanding future contracts. As of December 31, 2004 and 2003, cash in the amount of $664,900 and $1,866,400 was on deposit.

Inventories

Inventories of well equipment, parts and supplies are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased in excess of deliveries to customers and is recorded at the lower of cost or market.

Oil and Gas Properties

Exploration and development costs are accounted for by the successful efforts method.

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Property acquisition costs are capitalized when incurred. Geological and geophysical costs and delay rentals are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered economically producible reserves. If reserves are not discovered, such costs are expensed as dry holes. Development costs, including equipment and intangible drilling costs related to both producing wells and developmental dry holes, are capitalized.

Unproved properties or leases are written-off to expense when it is determined that they will expire or be abandoned.

Costs of proved properties, including leasehold acquisition, exploration and development costs and equipment, are depreciated or depleted by the unit-of-production method based on estimated proved developed oil and gas reserves.

Upon sale or retirement of complete fields of depreciable or depletable property, the net cost thereof, less proceeds or salvage value, is credited or charged to income. Upon retirement of a partial unit of property, the cost thereof is charged to accumulated depreciation and depletion.

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. The Company adopted SFAS No. 144 "Accounting for the Impairment or Disposal on Long-Lived Assets" on January 1, 2002. The adoption of SFAS No. 144 did not affect the Company's balance sheets.

In accordance with SFAS No. 144, long-lived assets, such as property, plant, and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Maintenance and repairs are charged to expense as incurred. Major renewals and betterments are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion and amortization are removed from the accounts, the proceeds applied thereto and any resulting gain or loss is reflected in income.

Buildings

Buildings are carried at cost and depreciated on the straight-line method over estimated useful lives of 30 years.

Asset Retirement Obligations

The Company incurs retirement obligations for its well drilling operations under FASB Statement No. 143, "Accounting for Asset Retirement Obligations". This requires entities to record the fair value of a liability for an asset retirement obligation in the period incurred and a corresponding increase in the carrying amount of the long-lived assets. The costs associated with this liability are capitalized as part of the related long-lived asset and depreciated. The Company adopted FASB No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $198,600 (net of taxes of $121,700). Since adoption the obligation has increased to $783,500 as of December 31, 2004 due to the additional wells purchased and drilled by the Company and accretion, offset in part by wells plugged.

Advances for Future Drilling Contracts

Represents funds received from Partnerships and other joint ventures for drilling activities which have not been completed and accordingly have not yet been recognized as income in accordance with the Company's income recognition policies.

Retirement Plans

The Company has a 401-K contributory retirement plan (401-K Plan) covering full-time employees. The Company provides a discretionary matching of employee contributions to the plan.

The Company also has a profit sharing plan covering full-time employees. The Company's contributions to this plan are discretionary.

The Company has a deferred compensation arrangement covering executive officers of the Company as a supplemental retirement benefit.

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our publicly registered drilling programs using the percentage of completion method. These contracts are footage rate based and completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services. The percentage of completion method measures the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed continually during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts would be recorded at the time that our estimated costs exceeded the contract revenue. The Company has not experienced any contract losses in 2004, 2003 or 2002.

Natural gas marketing is recorded on the gross accounting method. Riley Natural Gas (“Riley”), our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. Riley has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because Riley takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership.

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold by the Company under contracts with terms ranging from one month to three years. Virtually all of the Company’s contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company’s revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Company currently uses the “Net-Back” method of accounting for transportation arrangements of our natural gas sales. The Company sells gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by our customers and reflected in the wellhead price.

Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered in a stock tank, collection of revenue from the sale is reasonably assured and the sales price is determinable. The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company's crude oil production is sold to purchasers at or near the Company's wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

Well operations and pipeline income is recognized when persuasive evidence of an arrangement exists, services have been rendered, collection of revenues is reasonably assured and the sales price is fixed or determinable. The Company is paid a monthly operating fee for each well it operates for outside owners including the limited partnerships sponsored by the Company. The fee is competitive with rates charged by other operators in the area. The fee covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

Income Taxes

Income taxes are accounted for under the asset and liability method.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Derivative Financial Instruments

The Company accounts for derivatives and hedging in accordance with FASB Statement No. 133 Accounting for Derivative Instruments and Certain Hedging Activities, as amended which requires that all derivatives be recorded on the consolidated balance sheet at their fair values. On the date the derivative contract is entered into, the Company designates the derivative as either a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability ("Cash flow" hedge), or a non-hedging derivative. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash-flow hedges to specific firm commitments. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, the Company discontinues hedge accounting prospectively. No hedging activities were discontinued during 2004 or 2003.

Changes in fair value of a derivative that is highly effective and that is designated and qualifies as a cash-flow hedge are recorded in other comprehensive income, until earnings are affected by the variability in cash flows of the designated hedged item. Changes in the fair value of non-hedging derivatives are reported in current-period earnings. The Company discontinues hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised. Additionally, if the derivative is designated as a hedging instrument, and it is subsequently determined to be probable that a forecasted transaction will not occur or management determines that designation of the derivative as a hedging instrument is no longer appropriate, hedge accounting will be discontinued.

The Company uses derivative financial instruments for several purposes. The Company manages its exposure to price fluctuations in selling and producing natural gas by entering into natural gas future contracts and options contracts.

Stock Compensation

The Company applies the intrinsic-value based method of accounting prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations including FASB Interpretation No. 44, "Accounting for Certain Transactions involving Stock Compensation, an interpretation of APB Opinion No. 25", to account for its fixed-plan stock options. Under this method, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. FASB Statement No. 123, "Accounting for Stock-Based Compensation" and FASB Statement No. 148, "Accounting for Stock Based Compensation- Transition and Disclosure, an amendment of FASB Statement No. 123", established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. As permitted by existing accounting standards, the Company has elected to continue to apply the intrinsic-value-based method of accounting described above, and has adopted only the disclosure requirements of Statement 123, as amended. If the fair-value-based method had been applied to all outstanding and unvested awards in each period, the impact in 2004 would have been $18,400. There would have been no impact or reported net income in 2003 or 2002.

Compensation expense for stock options is measured as the excess, if any, of the quoted market price of the Company stock at the date of the grant over the amount an optionee must pay to acquire the stock. The Company records compensation expense for restricted stock awards based on the quoted market price of the Company' stock at the date of grant and vesting period.

The pro forma amounts that would have been reported if FASB 123 had been in effect for all years are based on the fair value of the stock-based awards granted for each year and recognized over the vesting period.

The fair value at date of grant for a common stock option granted under Company's option plan during 2004 was $16.75. The fair value of each option granted during 2004 was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions.

Dividend yield	0%
Expected volatility	39.71%
Risk-free interest rate	4.06%
Expected option life (in years)	7.0

As of December 31, 2004, there was approximately $283,000 of total unrecognized, pre-tax compensation cost related to non-vested stock options. This cost is expected to be recognized over four years. The Company will adopt the provisions of FASB Statement No. 123R (revised 2004), Share-Based Payment, in 2005 regarding stock compensation as discussed below. The Company will adopt the provisions of FASB Statement No. 123R (revised 2004), "Share-Based Payment", in 2005 regarding stock compensation as discussed below. Upon adoption of FASB Statement No. 123R, such cost will be recognized directly in our consolidated statement of income.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and debt obligations are estimated to be substantially the same as the fair values as of December 31, 2004 and 2003.

New Accounting Standards

The FASB issued FIN 46, “Consolidation of Variable Interest Entities”, in January 2003 and amended the interpretation in December 2003. A variable interest entity (VIE) is an entity in which its voting equity investors lack the characteristics of having a controlling financial interest or where the existing capital at risk is insufficient to permit the entity to finance its activities without receiving additional financial support from other parties. FIN 46 requires the consolidation of entities which are determined to be VIEs when the reporting company determines itself to be the primary beneficiary (the entity that will absorb a majority of the VIE's expected losses, receive a majority of the VIE's residual returns, or both). The amended interpretation was effective for the first interim or annual reporting period ending after March 15, 2004, with the exception of special purpose entities for which the statement was effective for periods ending after December 15, 2003. We have completed a review of our partnership investments and have determined that those entities do not qualify as VIEs.

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), “Share-Based Payment” which is a revision of FASB Statement No. 123, “Accounting for Stock-Based Compensation”. Statement 123R supercedes APB opinion No. 25, “Accounting for Stock Issued to Employees”, and amends FASB Statement No. 95, “Statement of Cash Flows”. Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The provisions of this statement becomes effective for our third quarter 2005. Management has not determined the impact that this statement will have on our consolidated financial statements.

(2) Notes and Accounts Receivable

Included in other assets are noncurrent accounts receivable as of December 31, 2004 and 2003, in the amounts of $608,500 and $819,700 net of an allowance for doubtful accounts of $224,400 and $338,100, respectively.

The allowance for doubtful current accounts receivable as of December 31, 2004 and 2003 was $164,600 and $149,200, respectively.

(3) Long-Term Debt

The Company has a credit facility with J. P. Morgan Chase Bank NA (formerly Bank One, NA) and BNP Paribas of $100 million subject to and secured by adequate levels of oil and gas reserves. The current total borrowing base is $80.0 million of which the Company has activated $60 million of the facility. The Company is required to pay a commitment fee of 1/4 percent on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2008.

As of December 31, 2004 and 2003 the outstanding balance was $21,000,000 and $53,000,000, respectively. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. As of December 31, 2004 and 2003 the Company was in compliance with all financial covenants in the credit agreement. At December 31, 2004, the outstanding balance was subject to a prime rate of 5.25%.

(4) Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2004 and 2003 are presented below:

	2004	2003
Deferred tax assets:		
Allowance for doubtful accounts	$ 159,100	189,500
Drilling notes	57,200	73,500
Alternative minimum tax credit carryforwards (Section 29)	-	437,400
Future abandonment	725,500	614,900
Deferred compensation	692,100	1,784,200
Other	21,800	27,700
Total gross deferred tax assets	1,655,700	3,127,200
Less valuation allowance	-	-
Deferred tax assets	1,655,700	3,127,200
Less current deferred tax assets (included in prepaid expenses)	(337,300)	(1,957,400)
Net non-current deferred tax assets	1,318,400	1,169,800
Deferred tax liabilities:		
Properties and equipment, principally due to differences in Depreciation and amortization	(32,814,500)	(23,842,200)
Total gross deferred tax liabilities	(32,814,500)	(23,842,200)
Net deferred tax liability	(31,496,100)	(22,672,400)
Deferred income tax assets related to adoption of FASB 143	121,700	121,700
Deferred income tax assets related to AOCI	1,531,200	750,500
Net deferred tax liability	$(29,843,200)	$(21,800,200)

Accumulated other comprehensive loss is net of tax of $1,531,200 and $750,500 as of December 31, 2004 and 2003, respectively.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

(5) Stockholders' Equity

Changes in capital during 2004 and 2003 are as follows:

	Common stock issued					
	Number Of Shares	Amount	Additional Paid-in-capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2002	15,734,767	157,300	29,316,800	73,430,100	(1,782,000)	101,122,200
Amortization of stock award	-	-	8,900	-	-	8,900
Repurchase and cancellation of treasury stock, r	(106,334)	(1,100)	(747,600)			(748,700)
Net income	-	-	-	22,619,100	-	22,619,100
Comprehensive income:						
Reclassification adjustment for settlement of c Included in net income (net of tax of $583,9	-	-	-	-	917,200	
Changes in fair value of outstanding hedging positions and interest rate swap (net of tax of $200,000)	-	-	-	-	(314,100)	
Other comprehensive income					603,100	603,100
Comprehensive income						23,222,200
Balance, December 31, 2003	15,628,433	$156,200	28,578,100	96,049,200	(1,178,900)	123,604,600
Issuance of common stock						
Exercise of employee stock options	1,100,000	11,000	4,981,700	-	-	4,992,700
Stock Award	23,380	200	(200)	-	-	0
Amortization of stock award	-	-	3,700	-	-	3,700

Repurchase and cancellation of treasury stock, net	(162,489)	(1,600)	(4,155,800)	-	-	(4,157,400)
Income tax benefit from exercise of stock options	-	-	7,394,800	-	-	7,394,800
Net income	-	-	-	34,060,600	-	34,060,600
Comprehensive income:						
Reclassification adjustment for settlement of contracts						
Included in net income (net of tax of $2,084,400)	-	-	-	-	3,274,000	
Changes in fair value of outstamding hedging positions						
and interest rate swap (net of tax of $2,865,000)					(4,500,100)	
Other comprehensive loss					(1,226,100)	(1,226,100)
Comprehensive income:						32,834,500
Balance, December 31, 2004	16,589,324	$165,800	36,802,300	130,109,800	(2,405,000)	164,672,900

See accompanying notes to consolidated financial statements.

Options

Outstanding options as of December 31, 2004, 2003 and 2002 were as follows:

	Number of Shares	Average Exercise Price	Range of Exercise Prices
Outstanding December 31, 2002	1,160,000	$4.48	1.125 - 6.25
Exercised	-	-	-
Outstanding December 31, 2003	1,160,000	$4.48	1.125 - 6.25
Granted	16,800	37.15	37.15
Exercised	(1,100,000)	4.48	1.125 - 6.25
Outstanding December 31, 2004	76,880	$11.64	3.875 – 37.15

As of December 31, 2004, there were 60,000 options outstanding and exercisable at the a $3.75 to $6.25 exercise price which have a weighted average remaining contractual life of 3.9 years and a weighted average exercise price of $5.40. Also as of December 31, 2004 there were 16,880 options outstanding and exercisable at a $37.15 exercise price having a weighted average remaining contractual life of 10 years.

Common Stock Repurchase

On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. From inception of the program until December 31, 2004, the Company has repurchased 109,200 shares at an average price of $6.86. This program is scheduled to expire on December 31, 2004. The following activity has occurred since inception of the plan on March 13, 2003 until December 31, 2004.

Month of Purchase	March, 2003	April, 2003	September, 2003
Average Price paid per share	$6.08	$6.48	$11.15
Broker/Dealer	McDonald Investments	McDonald Investments	McDonald Investments
Number of Shares Purchased	46,500	49,900	12,800
Remaining Number of Shares to Purchase	738,500	688,600	675,800

In March 2004, the Compensation Committee of the Board of Directors approved a repurchase of 48,650 shares of common stock from one of the Company's officers. The repurchase price of the common stock was the closing price on the date of the repurchase of $26.61 per share and totaled $1,294,600 which approximated the tax savings to be realized by the Company as a result of the exercise of said officer's non-qualified stock options in 2004. The Company also repurchased 1,703 shares from an employee upon retirement from the Company in June, 2004. Such treasury stock was subsequently cancelled.

At a meeting held on Friday, March 18, 2005 the Board of Directors of Petroleum Development Corporation approved a stock repurchase plan to allow the Company to repurchase up to 2% of the Company's common stock in 2005. The Company intends at a minimum to purchase adequate shares to insure no dilution from employee stock compensation plans and may also make open market purchases from time to time.

Stock Redemption Agreement

The Company has stock repurchase agreements with four executive officers of the Company. The agreements require the Company to maintain life insurance on each executive in the amount of $1,000,000. The agreements provide that the Company shall utilize the proceeds from such insurance to purchase from such executives' estates or heirs, at their option, shares of the Company's stock. The purchase price for the outstanding common stock is to be based upon the average closing asked price for the Company's stock as quoted by NASDAQ on the date of purchase. The Company is not required to purchase any shares in excess of the amount provided for by such insurance. During the fourth quarter of 2003, the Company received $1,000,000 in life insurance proceeds which was recorded as other income from the death of the Company's Chief Financial Officer who had a stock repurchase agreement. In May 2004, the Company repurchased 50,487 shares of common stock from the estate of the Company's former officer in accordance with the terms of this agreement. The repurchase price of the stock was $27.73 per share (the 90-day average prior to the repurchase per contract). The repurchase totaled $1,400,000 of which $1,000,000 was funded by the life insurance proceeds.

(6) Employee Benefit Plans

The Company sponsors a qualified deferred compensation plan that enables eligible employees to contribute a portion of their compensation through payroll deductions in accordance with specific guidelines. The Company matches a percentage of the employees' contributions up to certain limits. Expenses related to this plan amounted to $382,700 and $305,500 for 2004 and 2003, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $300,000 and $250,000 to the plan in cash during 2004 and 2003, respectively.

During 2003 and 2002 the Company expensed $90,000 each year under a deferred compensation arrangement with certain executive officers of the Company. These amounts were paid during 2003 to such executive officers.

The Company has a deferred compensation arrangement covering certain executive officers of the Company as a supplemental retirement benefit. During 2004 and 2003 the Company expensed $171,900 and $181,900, respectively, and has recorded a related liability in the amount $1,000,200 and $868,300 as of December 31, 2004 and 2003, respectively. The Company began paying the retirement benefit during 2004 to the estate of one of the Company's former officers. The Company paid $40,000 during 2004.

The Company maintains a non-qualified deferred compensation plan created for non-employee directors of the Company. The amount of compensation deferred by each Participant is based on Participant elections.

(7) Transactions with Affiliates

Funds held for future distribution on the consolidated balance sheet of $12,911,800 and $8,410,900 primarily represents amounts owed to affiliated partnerships as of December 31, 2004 and 2003, respectively.

The Company provided oil and gas well drilling services and well operations services to affiliated partnerships. Substantially all of the Company's oil and gas well drilling operations, well operations and pipeline income and other income (except for $1.0 million of life insurance proceeds in 2003 discussed in Note 5) was for such partnerships. Related services of tax return preparation and other services relating to the operation of the partnerships are recorded in other income. Amounts due from the affiliated partnerships as of December 31, 2004 and 2003 were $68,100 and $929,600, and are included in notes and accounts receivable.

The Company through its wholly-owned subsidiary, PDC Securities Incorporated, acts as Dealer-Manager of the Public Drilling Partnerships. PDC Securities Incorporated receives the applicable commissions and marketing allowances from the Escrow Agent of the Drilling Program and distributes them to the Soliciting Broker/Dealers who sell the programs. The commissions and marketing allowances received by PDC Securities are included in other income net of the commissions distributed to the soliciting broker/dealers in the amounts of $9,747,600 and $7,994,300 for the years ended December 31, 2004 and 2003, respectively. The net commissions and marketing allowance amounts included in other income were less than $1,000 for each of the years ending December 31, 2004 and 2003.

During 2004 and 2003, the Company paid $22,500 and $30,000, respectively, to the Corporate Secretary's law firm for various legal services.

(8) Commitments and Contingencies

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities and industrial customers. No customer accounted for 10% or more of the Company's total revenues in 2004. One customer accounted for 10.3% and 10.8% of total revenues in 2003 and 2002, respectively.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's hedging instruments or the counterparties to the Company's gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses in 2004 or 2003.

Substantially all of the Company's drilling programs contain a repurchase provision where Investing Partners may request the Company to purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are requested by the investors, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $6.6 million. The Company has adequate liquidity to meet this obligation. During 2004, the Company paid $408,260 under this provision for the repurchase of partnership units.

The Company's drilling programs formed since 1996 contain a performance standard which states that if certain performance levels are not met, the Company must remit a payment equal to one-half of its share of revenue from such partnership to the investing partners. During 2004 and 2003 the Company paid partnerships a total of $597,300 and $385,400, respectively in accordance with the provision.

During the fourth quarter of 2003, the Company recorded a liability in accordance with the death benefit of the employment contract of the Company's Chief Financial Officer in the amount of $852,700.

As Managing General Partner of 10 private partnerships and 62 public partnerships the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes its and its subcontractors casualty insurance coverage is adequate to meet this potential liability.

In order to secure the services for drilling rigs, the Company makes commitments to the drilling contractor which call for penalties for a specified amount of time if the Company ceases to use such drilling rigs, an event that is not anticipated to occur. As of December 31, 2004, the Company has an outstanding commitment for $1,604,250.

The Company drilled one exploratory well in 2004 and plans additional exploratory wells in 2005. As of the date of this report, the exploratory well had been completed and testing was underway but the well had not been classified as successful or dry. Testing of the well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing in the second quarter of 2005. If the well is determined to be a dry hole, its costs will be expensed in the period when the determination is made as required by the successful efforts method of accounting. The cost of the well as of December 31, 2004 is $4,169,903.

From time to time the Company is a party to various legal proceedings in the ordinary course of business. The Company is not currently a party to any litigation that it believes would have a materially adverse affect on the Company's business, financial condition, results of operations, or liquidity.

(9) Lease Obligations

The Company has entered into certain operating leases on behalf of itself and its Partnerships principally for the leasing of natural gas compressors on its Michigan operating facilities and office printing and copying equipment. The future minimum lease payments under these non-cancellable operating leases as of December 31, 2004 are as follows:

Year	Lease Amount
2005	$307,900
2006	209,400
2007	153,900
2008	127,200
2009	45,300
Thereafter	52,000
	$895,700

The Company's share of this lease expense for operating leases for the years ended December 31, 2004 and 2003 was $310,000 and $574,700, respectively.

(10) Purchases of Oil and Gas Properties

During the second quarter of 2003, the Company purchased 166 wells in the Denver Julesburg Basin in northeastern Colorado from Williams Production RMT Company for $28 million. The Company estimates the acquisition included approximately 22.6 billion cubic feet (Bcf) of proved developed producing (PDP) and 3.4 Bcf of proved developed non-producing reserves (PDNP), all of which is natural gas. The Company received approval for increased density well spacing in 2004. The Company drilled twenty new Niobrara wells on the property in 2004. The Company estimates that there are approximately 100 remaining increased density well locations, approximately 60 of which the Company plans to develop in 2005.

During the fourth quarter of 2003, the Company purchased from one of its unaffiliated joint venture partners in the Denver-Julesburg Basin in Weld County, Colorado approximately 3.1 billion cubic feet equivalent (Bcfe) of proved developed producing reserves from interests in 20.6 net wells (230 gross) and 1.8 Bcfe of proved developed non-producing reserves from interests in 17 net wells (183 gross). The purchase price was $5.2 million which also included over 30 additional drilling locations.

During the fourth quarter of 2003, the Company purchased from an unaffiliated party 97 gross wells (73 net) in the Denver-Julesburg Basin located in northeast Colorado and northwestern Kansas for $6.0 million. This purchase added approximately 4.5 billion cubic feet equivalent (Bcfe) of proved developed producing and proved developed non-producing reserves to the Company's oil and gas reserves along with 100,000 acres of oil and gas leases.

(11) Derivative Financial Instruments

The futures and option contracts hedge forecasted natural gas purchases and sales, generally forecasted to occur within a three year period. The Company does not hold or issue derivatives for trading or speculative purposes. In addition, an interest rate swap agreement was used to reduce the potential impact of increases in interest rates on variable rate long-term debt.

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production and CIG-based contracts traded by JP Morgan Chase Bank, NA for Colorado production. These hedging arrangements have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the hedge relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these hedging arrangements are structured to reduce the Company's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Company might otherwise have received from price increases associated with the hedged commodity. The Company's policy prohibits the use of natural gas future and option contracts for speculative purposes.

The following tables summarize the open futures and options contracts for Riley Natural Gas and PDC as of December 31, 2004 and 2003.

Riley Natural Gas
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of December 31, 2004					
Natural Gas	Sale	3,260,000	$5.60	$18,249,250	($1,982,964)
Natural Gas	Purchase	1,130,000	$6.77	$7,644,540	($486,490)
Natural Gas	Floor	530,000	$5.30		$134,242
Natural Gas	Ceiling	265,000	$7.00		($85,541)
Contracts maturing in 12 months following December 31, 2004					
Natural Gas	Sale	2,230,000	$5.84	$13,014,810	($841,102)
Natural Gas	Purchase	860,000	$6.94	$5,965,490	($591,340)
Natural Gas	Floor	530,000	$5.30		$134,242
Natural Gas	Ceiling	265,000	$7.00		($85,541)
Prior Year Total Contracts as of December 31, 2003					
Natural Gas	Sale	2,660,000	$4.58	$12,174,130	($1,810,500)
Natural Gas	Purchase	820,000	$5.17	$4,243,420	$270,200

The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 27 months.

Petroleum Development Corporation
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Market Value
Total Contracts as of December 31, 2004					
Natural Gas	Purchase	46,776	$6.63	$310,339	($17,806)
Natural Gas	Floor	3,562,020	$4.56		$337,842
Natural Gas	Ceiling	1,556,010	$5.39		($1,526,868)
Crude Oil	Floor	166,536	$32.30		$141,880
Crude Oil	Ceiling	83,268	$40.00		($450,405)
Contracts maturing in 12 months following December 31, 2004					
Natural Gas	Sale				
Natural Gas	Purchase	46,776	$6.63	$310,339	($17,806)
Natural Gas	Floor	3,562,020	$4.56		$337,842
Natural Gas	Ceiling	1,556,010	$5.39		($1,526,868)
Crude Oil	Floor	166,536	$32.30		$141,880
Crude Oil	Ceiling	83,268	$40.00		($450,405)
Prior Year Total Contracts as of December 31, 2003					
Natural Gas	Sale	53,300	$5.40	$288,000	($40,000)
Natural Gas	Purchase	45,700	$4.77	$218,100	$30,400
Natural Gas	Floor	2,597,800	$4.29		$185,300
Natural Gas	Ceiling	691,200	$5.23		($127,800)

The maximum term over which PDC is hedging exposure to the variability of cash flows for commodity price risk is 12 months.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2004 and 2003, cash in the amount of $664,900 and $1,866,400 was on deposit.

An interest rate swap agreement was used to reduce the potential impact of increases in interest rates on variable rate long-term debt. Such swap agreement expired in October 2004. At December 31, 2003, the Company was a party to an interest rate swap agreement which expired on October 11, 2004. The agreement required the Company, on a quarterly basis, to make a fixed-rate interest payment of 6.89% plus its current LIBOR rate margin (+1.50% At December 31, 2003) on a $10,000,000 amount related to its outstanding line of credit.

The fair value of the interest rate swap agreement was $(436,800), $(266,900) net of tax at December 31, 2003. Current market pricing models were used to estimate fair value.

By using derivative financial instruments to hedge exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

Changes in the fair value of natural gas futures contracts designated as hedging instruments and that effectively offset the variability of cash flows associated with anticipated sales of natural gas are reported in accumulated other comprehensive income (AOCI). These amounts subsequently are reclassified into gas purchases for RNG and gas sales for PDC when the related gas is sold and affects earnings. Changes in the fair value of the interest rate swap agreement were reclassified into interest expense.

(12) Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred by the Company in oil and gas property acquisition, exploration and development are presented below:

	Years Ended December 31,	
	2004	2003
Property acquisition cost:		
Proved undeveloped properties	$ 4,583,000	6,167,800
Producing properties	720,000	33,946,600
Development costs	36,870,400	30,630,100
	$42,173,400	70,744,500

The proved reserves attributable to the development costs in the above table were 40,716,000 Mcf and 358,000 bbls for 2004, and 27,719,000 Mcf and 517,000 bbls for 2003. Of the above development costs incurred for the years ended December 31, 2004 and 2003 the amounts of $1,819,619 and $4,289,600, respectively, were incurred to develop proved undeveloped properties from the prior year end.

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells and to provide facilities to extract, treat, gather and store oil and gas.

(13) Oil and Gas Capitalized Costs

Aggregate capitalized costs for the Company related to oil and gas exploration and production activities with applicable accumulated depreciation, depletion and amortization are presented below:

	December 31,	
	2004	2003
Proved properties:		
Tangible well equipment	$157,787,800	133,356,900
Intangible drilling costs	123,171,200	110,087,300
Undeveloped properties	9,864,300	7,576,900
Capitalized asset retirement cost	613,400	537,800
	291,436,700	251,558,900
Less accumulated depreciation, depletion and amortization	80,762,100	64,205,100
	$210,674,600	187,353,800

(14) Net Proved Oil and Gas Reserves (Unaudited)

The proved reserves of oil and gas of the Company have been estimated by an independent petroleum engineer, Wright & Company, Inc. at December 31, 2004 and 2003. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

	Oil (BBLS)	
	2004	2003
Proved developed and undeveloped reserves:		
Beginning of year	3,029,000	2,073,000
Revisions of previous estimates	305,000	533,000
Beginning of year as revised	3,334,000	2,606,000
New discoveries and extensions:		
Rocky Mountain Region	358,000	517,000
Dispositions to partnerships	(12,000)	(112,000)
Acquisitions:		
Rocky Mountain Region	17,000	307,000
Production	(381,000)	(289,000)
End of year	3,316,000	3,029,000
Proved developed reserves:		
Beginning of year	2,889,000	1,849,000
End of year	3,190,000	2,889,000

	Gas (MCF)	
	2004	2003
Proved developed and undeveloped reserves:		
Beginning of year	180,998,000	128,851,000
Revisions of previous estimates	(10,635,000)	4,394,000
Beginning of year as revised	170,363,000	133,245,000
New discoveries and extensions:		
Rocky Mountain Region	40,716,000	27,719,000
Dispositions to partnerships	(4,240,000)	(4,410,000)
Acquisitions:		
Michigan Basin	96,000	265,000
Rocky Mountain Region	242,000	32,169,000
Appalachian Basin	744,000	722,000
Production	(10,372,000)	(8,712,000)
End of year	197,549,000	180,998,000
Proved developed reserves:		
Beginning of year	134,936,000	94,847,000
End of year	146,152,000	134,936,000

(15) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves (Unaudited)

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

	As of December 31,	
	2004	2003
Future estimated revenues	$1,298,394,000	1,088,415,000
Future estimated production costs	(319,065,000)	(250,735,000)
Future estimated development costs	(95,498,000)	(65,275,000)
Future estimated income tax expense	(332,497,000)	(265,707,000)
Future net cash flows	551,334,000	506,698,000
10% annual discount for estimated timing of cash flows	(317,099,000)	(289,408,000)
Standardized measure of discounted future estimated net cash flows	$234,235,000	217,290,000

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Years Ended December 31, 2004	2003
Sales of oil and gas production, net of production costs	$(52,974,000)	(36,810,000)
Net changes in prices and production costs	36,656,000	162,422,000
Extensions, discoveries and improved recovery, Less related cost	135,816,000	114,533,000
Dispositions to partnerships	(16,782,000)	(12,936,000)
Acquisitions	6,451,000	139,078,000
Development costs incurred during the period	36,870,000	30,630,000
Revisions of previous quantity estimates	(34,611,000)	21,388,000
Changes in estimated income taxes	(66,790,000)	(159,831,000)
Accretion of discount	(27,691,000)	(139,653,000)
	$16,945,000	118,821,000

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

(16) Business Segments (Thousands)

PDC's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 2,700 wells from which it derives oil and gas working interests. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31, 2004 and 2003 is as follows:

	2004	2003
SEGMENT ASSETS		
Drilling and Development	$64,348	$62,546
Natural Gas Marketing	28,689	17,006
Oil and Gas Sales	221,516	204,849
Well Operations	16,518	11,602
Unallocated amounts		
Cash	112	800
Other	10,210	9,919
Total	$341,393	$306,722

EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS		
Drilling and Development	$ 4,583	6,168
Natural Gas Marketing	6	-
Oil and Gas Sales	37,590	63,588
Well Operations	1,911	2,944
Unallocated amounts	1,302	342
Total	$ 45,392	73,042

(17) Subsequent Event

In January 2005, the Company sold a portion of one of its undeveloped Garfield County, Colorado leases to another operator. The gain on such sale to be recorded in the first quarter 2005 was approximately $5.2 million, net of a $1.0 million liability recorded for a future commitment. The interest sold consisted of half the Company's leasehold interest on a "checkerboard" pattern. The Company will retain the other half of the lease. The terms of the agreement require the purchaser to drill a number of wells over a period of time on the acquired acreage. If the drilling requirements are not met part or all of the lease will revert to the Company.

APPENDIX A

FORM OF
LIMITED PARTNERSHIP AGREEMENT
OF
PDC 2004-___ LIMITED PARTNERSHIP
[PDC 2005- LIMITED PARTNERSHIP]
[PDC 2006- LIMITED PARTNERSHIP]

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FORM OF
LIMITED PARTNERSHIP AGREEMENT
OF
PDC 2004- LIMITED PARTNERSHIP,
[PDC 2005- LIMITED PARTNERSHIP,]
[PDC 2006- ___ LIMITED PARTNERSHIP,]
A WEST VIRGINIA LIMITED PARTNERSHIP

This LIMITED PARTNERSHIP AGREEMENT (the "Agreement") is made as of this ___ day of ___________, 2004 [or 2005 or 2006, as appropriate] by and among Petroleum Development Corporation, a Nevada corporation, as managing general partner (the "Managing General Partner"), Steven R. Williams, a resident of West Virginia, as the Initial Limited Partner, and the Persons whose names are set forth on Exhibit A attached hereto, as additional general partners (the "Additional General Partners") or as limited partners (the "Limited Partners" and, collectively with Additional General Partners, the "Investor Partners"), pursuant to the provisions of the West Virginia Uniform Limited Partnership Act (the "Act"), on the following terms and conditions:

The Partnership

b. Organization. Subject to the provisions of this Agreement, the parties hereto do hereby form a limited partnership (the "Partnership") pursuant to the provisions of the Act. The Partners hereby agree to continue the Partnership as a limited partnership pursuant to the provisions of the Act and upon the terms and conditions set forth in this Agreement.

c. Partnership Name. The name of the Partnership shall be PDC 2004- Limited Partnership [or PDC 2005- Limited Partnership, or PDC 2006- Limited Partnership], a West Virginia limited partnership, and all business of the Partnership shall be conducted in such name. The Managing General Partner may change the name of the Partnership upon ten days notice to the Investor Partners. The Partnership shall hold all of its property in the name of the Partnership and not in the name of any Partner.

d. Character of Business. The principal business of the Partnership shall be to acquire Leases, drill sites, and other interests in oil and/or gas properties and to drill for oil, gas, hydrocarbons, and other minerals located in, on, or under such properties, to produce and sell oil, gas, hydrocarbons, and other minerals from such properties, and to invest and generally engage in any and all phases of the oil and gas business. Such business purpose shall include without limitation the purchase, sale, acquisition, disposition, exploration, development, operation, and production of oil and gas properties of any character. The Partnership shall not acquire property in exchange for Units. Without limiting the foregoing, Partnership activities may be undertaken as principal, agent, general partner, syndicate member, joint venturer, participant, or otherwise.

e. Principal Place of Business. The principal place of business of the Partnership shall be at 103 East Main Street, Bridgeport, West Virginia, 26330. The Managing General Partner may change the principal place of business of the Partnership to any other place within the State of West Virginia upon ten days notice to the Investor Partners.

f. Term of Partnership. The Partnership shall commence on the date the Partnership is organized, as set forth in Section 1.01, and shall continue until terminated as provided in Article IX hereof. Notwithstanding the foregoing, if Investor Partners agreeing to purchase $7,000,000 with respect to each Limited Partnership in Units have not subscribed and paid for their Units by the Offering Termination Date, then this Agreement shall be void in all respects, and all investments of the Investor Partners shall be promptly returned together with any interest earned thereon and without any deduction therefrom. The Managing General Partner and its Affiliates may purchase up to 10% (and no more) of the Units subscribed for by Investor Partners in the Partnership; however, not more than $50,000 of the Units purchased by the Managing General Partner and/or its Affiliates will be applied to satisfying the minimum.

g. Filings.

i. A Certificate of Limited Partnership (the "Certificate") has been filed in the office of the Secretary of State of West Virginia in accordance with the provisions of the Act. The Managing General Partner shall take any and all other actions reasonably necessary to perfect and maintain the status of the Partnership as a limited partnership under the laws of West Virginia. The Managing General Partner shall cause amendments to the Certificate to be filed whenever required by the Act.

ii. The Managing General Partner shall execute and cause to be filed original or amended Certificates and shall take any and all other actions as may be reasonably necessary to perfect and maintain the status of the Partnership as a limited partnership or similar type of entity under the laws of any other states or jurisdictions in which the Partnership engages in business.

iii. The agent for service of process on the Partnership shall be Steven R. Williams or any successor as appointed by the Managing General Partner.

iv. Upon the dissolution of the Partnership, the Managing General Partner (or any successor managing general partner) shall promptly execute and cause to be filed certificates of dissolution in accordance with the Act and the laws of any other states or jurisdictions in which the Partnership has filed certificates.

h. Independent Activities. Each General Partner and each Limited Partner may, notwithstanding this Agreement, engage in whatever activities they choose, whether the same are competitive with the Partnership or otherwise, without having or incurring any obligation to offer any interest in such activities to the Partnership or any Partner. However, except as otherwise provided herein, the Managing General Partner and any of its Affiliates may pursue business opportunities that are consistent with the Partnership's investment objectives for their own account only after they have determined that such opportunity either cannot be pursued by the Partnership because of insufficient funds or because it is not appropriate for the Partnership under the existing circumstances. Neither this Agreement nor any activity undertaken pursuant hereto shall prevent the Managing General Partner from engaging in such activities, or require the Managing General Partner to permit the Partnership or any Partner to participate in any such activities, and as a material part of the consideration for the execution of this Agreement by the Managing General Partner and the admission of each Investor Partner, each Investor Partner hereby waives, relinquishes, and renounces any such right or claim of participation. Notwithstanding the foregoing, the Managing General Partner still has an overriding fiduciary obligation to the Investor Partners.

i. Definitions. Capitalized words and phrases used in this Agreement shall have the following meanings:

i. "Act" shall mean the Uniform Limited Partnership Act of the State of West Virginia, as set forth in §§ 47-9-1 through 47-9-63 thereof, as amended from time to time (or any corresponding provisions of succeeding law).

ii. "Additional General Partner" shall mean an Investor Partner who purchases Units as an additional general partner, and such partner's transferees and assigns. "Additional General Partners" shall mean all such Investor Partners. "Additional General Partner" shall not include, after a conversion, such Investor Partner who converts his interest into a Limited Partnership interest pursuant to Section 7.10 herein.

iii. "Administrative Costs" shall mean all customary and routine expenses incurred by the Managing General Partner for the conduct of program administration, including legal, finance, accounting, secretarial, travel, office rent, telephone, data processing and other items of a similar nature.

iv. "Affiliate" of a specified person shall mean (a) any person directly or indirectly owning, controlling, or holding with power to vote 10 percent or more of the outstanding voting securities of such specified person; (b) any person 10 percent or more of whose outstanding voting securities are directly or indirectly owned, controlled, or held with power to vote, by such specified person; (c) any person directly or indirectly controlling, controlled by, or under common control with such specified person; (d) any officer, director, trustee or partner of such specified person, and (e) if such specified person is an officer, director, trustee or partner, any person for which such person acts in any such capacity.

v. "Agreement" or "Partnership Agreement" shall mean this Limited Partnership Agreement, as amended from time to time.

vi. "Capital Account" shall mean, with respect to any Partner, the capital account maintained for such Partner pursuant to Section 3.01 hereof.

vii. "Capital Available for Investment" shall mean the sum of (a) Subscriptions, net of total underwriting and brokerage discounts, commissions, and expenses, up to an aggregate of 10½% of Subscriptions, and the Management Fee and (b) the Capital Contribution of the Managing General Partner.

viii. "Capital Contribution" shall mean the total investment, including the original investment, assessments, and amounts reinvested, by such Investor Partner to the capital of the Partnership pursuant to Section 2.02 herein, and, with respect to the Managing General Partner and the Initial Limited Partner, the total investment, including the original investment, assessments, and amounts reinvested, to the capital of the Partnership pursuant to Section 2.01 herein.

ix. "Code" shall mean the Internal Revenue Code of 1986, as amended from time to time (or any corresponding provisions of succeeding law).

x. "Cost," when used with respect to the sale of property to the Partnership, shall mean (a) the sum of the prices paid by the seller to an unaffiliated person for such property, including bonuses; (b) title insurance or examination costs, brokers' commissions, filing fees, recording costs, transfer taxes, if any, and like charges in connection with the acquisition of such property; (c) a pro rata portion of the seller's actual necessary and reasonable expenses for seismic and geophysical services; and (d) rentals and ad valorem taxes paid by the seller with respect to such property to the date of its transfer to the buyer, interest and points actually incurred on funds used to acquire or maintain such property, and such portion of the seller's reasonable, necessary and actual expenses for geological, engineering, drafting, accounting, legal and other like services allocated to the property cost in conformity with generally accepted accounting principles and industry standards, 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 expenses enumerated in this subsection (d) hereof shall have been incurred not more than 36 months prior to the purchase by the Partnership; provided that such period may be extended, at the discretion of the state securities administrator, upon proper justification, When used with respect to services, "cost" means the reasonable, necessary and actual expense incurred by the seller on behalf of the Partnership in providing such services, determined in accordance with generally accepted accounting principles. As used elsewhere, "cost" means the price paid by the seller in an arm's-length transaction.

xi. "Depreciation" shall mean, for each fiscal year or other period, an amount equal to the depreciation, amortization, or other cost recovery deduction allowable with respect to an asset for such year or other period, except that if the Gross Asset Value of an asset differs from its adjusted basis for federal income tax purposes at the beginning of such year or other period, Depreciation shall be an amount which bears the same ratio to such beginning Gross Asset Value as the federal income tax depreciation, amortization, or other cost recovery deduction for such year or other period bears to such beginning adjusted tax basis; provided, however, that if the federal income tax depreciation, amortization, or other cost recovery deduction for such year is zero, Depreciation shall be determined with reference to such beginning Gross Asset Value using any reasonable method selected by the Managing General Partner.

xii. "Development Well" shall mean a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

xiii. "Direct Costs" shall mean all actual and necessary costs directly incurred for the benefit of the Partnership and generally attributable to the goods and services provided to the Partnership by parties other than the Managing General Partner or its Affiliates. Direct costs shall not include any cost otherwise classified as organization and offering expenses, administrative costs, operating costs or property costs. Direct costs may include the cost of services provided by the Managing General Partner or its Affiliates if such services are provided pursuant to written contracts and in compliance with Section 5.07(e) of the Partnership Agreement.

xiv. "Drilling and Completion Costs" shall mean all costs, excluding Operating Costs, of drilling, completing, testing, equipping and bringing a well into production or plugging and abandoning it, including all labor and other construction and installation costs incident thereto, location and surface damages, cementing, drilling mud and chemicals, drillstem tests and core analysis, engineering and well site geological expenses, electric logs, costs of plugging back, deepening, rework operations, repairing or performing remedial work of any type, costs of plugging and abandoning any well participated in by the Partnership, and reimbursements and compensation to well operators, including charges paid to the Managing General Partner as unit operator during the drilling and completion phase of a well, plus the cost of the gathering system and of acquiring leasehold interests.

xv. "Dry Hole" shall mean any well abandoned without having produced oil or gas in commercial quantities.

xvi. "Exploratory Well" shall mean a well drilled to find commercially productive hydrocarbons in an unproved area, to find a new commercially productive horizon in a field previously found to be productive of hydrocarbons at another horizon, or to significantly extend a known prospect.

xvii. "Farmout" shall mean an agreement whereby the owner of the leasehold or working interest agrees to assign his interest in certain specific acreage to the assignees, retaining some interest such as an overriding royalty interest, an oil and gas payment, offset acreage or other type of interest, subject to the drilling of one or more specific wells or other performance as a condition of the assignment.

xviii. "General Partners" shall mean the Additional General Partners and the Managing General Partner.

xix. "Gross Asset Value" shall mean, with respect to any asset, the asset's adjusted basis for federal income tax purposes, except as follows:

1. The initial Gross Asset Value of any asset contributed by a Partner to the Partnership shall be the gross fair market value of such asset, as determined by the contributing Partner and the Partnership;

2. The Gross Asset Values of all Partnership assets shall be adjusted to equal their respective gross fair market values, as determined by the Managing General Partner, as of the following times: (a) the acquisition of an additional interest in the Partnership by any new or existing Partner in exchange for more than a de minimis Capital Contribution; (b) the distribution by the Partnership Property as consideration for an interest in the Partnership; and (c) the liquidation of the Partnership within the meaning of Treas. Reg. Section 1.704-1(b)(2)(ii)(g); provided, however, that the adjustments pursuant to clauses (a) and (b) in this subsection (2) shall be made only if the Managing General Partner reasonably determines that such adjustments are necessary or appropriate to reflect the relative economic interests of the Partners in the Partnership;

3. The Gross Asset Value of any Partnership asset distributed to any Partner shall be the gross fair market value of such asset on the date of distribution; and

4. The Gross Asset Values of Partnership assets shall be increased (or decreased) to reflect any adjustments to the adjusted basis of such assets pursuant to Code Section 734(b) or Code Section 743(b), but only to the extent that such adjustments are taken into account in determining Capital Accounts pursuant to Treas. Reg. Section 1.704-1(b)(2)(iv)(m) and Section 3.02(g) hereof; provided, however, that Gross Asset Values shall not be adjusted pursuant to this subsection (4) to the extent the Managing General Partner determines that an adjustment pursuant to subsection (2) hereof is necessary or appropriate in connection with a transaction that would otherwise result in an adjustment pursuant to this subsection (4).

If the Gross Asset Value of an asset has been determined or adjusted pursuant to subsections (1), (2), or (4) hereof, such Gross Asset value shall thereafter be adjusted by the Depreciation taken into account with respect to such asset for purposes of computing Profits and Losses.

xx. "IDC" shall mean intangible drilling and development costs.

xxi. "Independent Expert" shall mean a person with no material relationship with the Managing General Partner or its Affiliates who is qualified and who is in the business of rendering opinions regarding the value of oil and gas properties based upon the evaluation of all pertinent economic, financial, geologic and engineering information available to the Managing General Partner or its Affiliates.

xxii. "Initial Limited Partner" shall mean Steven R. Williams or any successor to his interest.

xxiii. "Investor Partner" shall mean any Person other than the Managing General Partner (i) whose name is set forth on Exhibit A, attached hereto, as an Additional General Partner or as a Limited Partner, or who has been admitted as an additional or Substituted Investor Partner pursuant to the terms of this Agreement, and (ii) who is the owner of a Unit. "Investor Partners" means all such Persons. All references in this Agreement to a majority in interest or a specified percentage of the Investor Partners shall mean Investor Partners holding more than 50% or such specified percentage, respectively, of the outstanding Units then held.

xxiv. "Lease" shall mean full or partial interests in: (i) undeveloped oil and gas leases; (ii) oil and gas mineral rights; (iii) licenses; (iv) concessions; (v) contracts; (vi) fee rights; or (vii) other rights authorizing the owner thereof to drill for, reduce to possession and produce oil and gas.

xxv. "Limited Partner" shall mean an Investor Partner who purchases Units as a Limited Partner, such partner's transferees or assignees, and an Additional General Partner who converts his interest to a limited partnership interest pursuant to the provisions of the Agreement. "Limited Partners" shall mean all such Investor Partners.

xxvi. "Management Fee" shall mean that fee to which the Managing General Partner is entitled pursuant to Section 6.06 hereof.

xxvii. "Managing General Partner" shall mean Petroleum Development Corporation or its successors, in their capacity as the Managing General Partner.

“Managing General Partner’s Drilling Compensation” shall mean the amount paid to the Managing General Partner for its services as managing general partner and operator during drilling and completion activities.

"Mcf" shall mean one thousand cubic feet of natural gas.

"Net Subscriptions" shall mean an amount equal to the total Subscriptions of the Investor Partners less the amount of Organization and Offering Costs of the Partnership.

"Nonrecourse Deductions" shall have the meaning set forth in Treas. Reg. Section 1.704-2(b)(1). The amount of Nonrecourse Deductions for a Partnership fiscal year shall equal the net increase in the amount of Partnership Minimum Gain during that fiscal year reduced (but not below zero) by the aggregate distributions during that fiscal year of proceeds of a Nonrecourse Liability that are allocable to an increase in Partnership Minimum Gain, determined according to the provisions of Treas. Reg. Section 1.704-2(c).

"Nonrecourse Liability" shall have the meaning set forth in Treas. Reg. Section 1.704-2(b)(3) and 1.752-1(a)(2).

"Offering Termination Date" shall mean December 31, 2004 with respect to Partnerships designated "PDC 2004- Limited Partnership"; December 30, 2005 with respect to Partnerships designated "PDC 2005- Limited Partnership"; and December 29, 2006 with respect to Partnerships designated "PDC 2006- Limited Partnership" or such earlier date as the Managing General Partner, in its sole and absolute discretion, shall elect.

"Oil and Gas Interest" shall mean any oil or gas royalty or lease, or fractional interest therein, or certificate of interest or participation or investment contract relative to such royalties, leases or fractional interests, or any other interest or right which permits the exploration of, drilling for, or production of oil and gas or other related hydrocarbons or the receipt of such production or the proceeds thereof.

"Operating Costs" shall mean expenditures made and costs incurred in producing and marketing oil or gas from completed wells, including, in addition to labor, fuel, repairs, hauling, materials, supplies, utility charges and other costs incident to or therefrom, ad valorem and severance taxes, insurance and casualty loss expense, and compensation to well operators or others for services rendered in conducting such operations.

"Organization and Offering Costs" shall mean all costs of organizing and selling the offering including, but not limited to, total underwriting and brokerage discounts and commissions (including fees of the underwriters' attorneys), expenses for printing, engraving, mailing, salaries of employees while engaged in sales activity, charges of transfer agents, registrars, trustees, escrow holders, depositaries, engineers and other experts, expenses of qualification of the sale of the securities under Federal and State law, including taxes and fees, accountants' and attorneys' fees and other front end fees.

"Overriding Royalty Interest" shall mean an interest in the oil and gas produced pursuant to a specified oil and gas lease or leases, or the proceeds from the sale thereof, carved out of the working interest, to be received free and clear of all costs of development, operation, or maintenance.

"Partner Minimum Gain" shall mean an amount, with respect to each Partner Nonrecourse Debt, equal to the Partnership Minimum Gain that would result if such Partner Nonrecourse Debt were treated as a Nonrecourse Liability, determined in accordance with Treas. Reg. Section 1.704-2(i).

"Partner Nonrecourse Debt" shall have the meaning set forth in Treas. Reg. Section 1.704-2(b)(4).

"Partner Nonrecourse Deductions" shall have the meaning set forth in Treas. Reg. Section 1.704-2(i)(2). The amount of Partner Nonrecourse Deductions with respect to a Partner Nonrecourse Debt for a Partnership fiscal year shall equal the net increase in the amount of Partner Minimum Gain attributable to such Partner Nonrecourse Debt during that fiscal year reduced (but not below zero) by proceeds of the liability distributed during that fiscal year to the Partner bearing the economic risk of loss for such liability that are both attributable to the liability and allocable to an increase in Partner Minimum Gain attributable to such Partner Nonrecourse Debt, determined in accordance with Treas. Reg. Section 1.704-2(i)(3).

"Partners" shall mean the Managing General Partner, the Initial Limited Partner, and the Investor Partners. "Partner" shall mean any one of the Partners. All references in this Agreement to a majority in interest or a specified percentage of the Partners shall mean Partners holding more than 50% or such specified percentage, respectively, of the outstanding Units then held.

"Partnership" shall mean the partnership pursuant to this Agreement and the partnership continuing the business of this Partnership in the event of dissolution as herein provided.

"Partnership Minimum Gain" shall have the meaning set forth in Treas. Reg. Section 1.704-2(b)(2) and 1.704-2(d)(1).

"Permitted Transfer" shall mean any transfer of Units satisfying the provisions of Section 7.03 herein.

"Person" shall mean any individual, partnership, corporation, trust, or other entity.

"Profits" and "Losses" shall mean, for each fiscal year or other period, an amount equal to the Partnership's taxable income or loss for such year or period, determined in accordance with Code Section 703(a) (for this purpose, all items of income, gain, loss, or deduction required to be stated separately pursuant to Code Section 703(a)(1) shall be included in taxable income or loss), with the following adjustments:

1. Any income of the Partnership that is exempt from federal income tax and not otherwise taken into account in computing Profits or Losses pursuant to this Section 1.08(tt) shall be added to such taxable income or loss;

2. Any expenditures of the Partnership described in Code Section 705(a)(2)(B) or treated as Code Section 705(a)(2)(B) expenditures pursuant to Treas. Reg. Section 1.704-1(b)(2)(iv)(i), and not otherwise taken into account in computing Profits or Losses pursuant to this Section 1.08(tt) shall be subtracted from such taxable income or loss;

3. In the event the Gross Asset Value of any Partnership asset is adjusted pursuant to Section 1.08(s)(2) or Section 1.08(s)(3) hereof, the amount of such adjustment shall be taken into account as gain or loss from the disposition of such asset for purposes of computing Profits or Losses.

4. Gain or loss resulting from any disposition of Partnership Property with respect to which gain or loss is recognized for federal income tax purposes shall be computed by reference to the Gross Asset Value of the property disposed of, notwithstanding that the adjusted tax basis of such property differs from its Gross Asset Value;

5. In lieu of the depreciation, amortization, and other cost recovery deductions taken into account in computing such taxable income or loss, there shall be taken into account Depreciation for such fiscal year or other period, computed in accordance with Section 1.08(s) hereof; and

6. Notwithstanding any other provisions of this Section 1.08(tt), any items which are specially allocated pursuant to this Agreement shall not be taken into account in computing Profits or Losses.

"Prospect" shall mean a contiguous oil and gas leasehold estate, or lesser interest therein, upon which drilling operations may be conducted. In general, a Prospect is an area in which the Partnership owns or intends to own one or more oil and gas interests, which is geographically defined on the basis of geological data by the Managing General Partner of such Partnership and which is reasonably anticipated by the Managing General Partner to contain at least one reservoir. An area covering lands which are believed by the Managing General Partner to contain subsurface structural or stratigraphic conditions making it susceptible to the accumulations of hydrocarbons in commercially productive quantities at one or more horizons. The area, which may be different for different horizons, shall be designated by the Managing General Partner in writing prior to the conduct of program operations and shall be enlarged or contracted from time to time on the basis of subsequently acquired information to define the anticipated limits of the associated hydrocarbon reserves and to include all acreage encompassed therein. A "prospect" with respect to a particular horizon may be limited to the minimum area permitted by state law or local practice, whichever is applicable, to protect against drainage from adjacent wells if the well to be drilled by the Partnership is to a horizon containing proved reserves.

"Prospectus" shall mean that Prospectus (including any preliminary prospectus), of which this Agreement is a part, pursuant to which the Units are being offered and sold.

"Proved Developed Oil and Gas Reserves" shall mean the 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 Oil and Gas Reserves" shall mean 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.

7. Reservoirs are considered proved if economic productibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) 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.

8. 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.

9. Estimates or proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) 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; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

"Proved Undeveloped Reserves" shall mean the 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.

"Reservoir" shall mean a separate structural or stratigraphic trap containing an accumulation of oil or gas.

"Roll-Up" shall mean a transaction involving the acquisition, merger, conversion, or consolidation, either directly or indirectly, of the Partnership and the issuance of securities of a roll-up entity. Such term does not include:

10. a transaction involving securities of the Partnership that have been listed for at least 12 months on a national exchange or traded through the National Association of Securities Dealers Automated Quotation National Market System; or

11. a transaction involving the conversion to corporate, trust or association form of only the Partnership if, as a consequence of the transaction, there will be no significant adverse change in any of the following:

a. voting rights;

b. the term of existence of the Partnership;

c. sponsor compensation; or

d. the Partnership's investment objectives.

"Roll-Up Entity" shall mean a partnership, trust, corporation or other entity that would be created or survive after the successful completion of a proposed roll-up transaction.

"Sponsor" shall mean any person directly or indirectly instrumental in organizing, wholly or in part, a program or any person who will manage or is entitled to manage or participate in the management or control of a program. "Sponsor" includes the managing and controlling general partner(s) and any other person who actually controls or selects the person who controls 25% or more of the exploratory, developmental or producing activities of the Partnership, or any segment thereof, even if that person has not entered into a contract at the time of formation of the Partnership. "Sponsor" does not include wholly independent third parties such as attorneys, accountants, and underwriters whose only compensation is for professional services rendered in connection with the offering of units. Whenever the context of these guidelines so requires, the term "sponsor" shall be deemed to include its affiliates.

"Subscription" shall mean the amount indicated on the Subscription Agreement that an Investor Partner has agreed to pay to the Partnership as his Capital Contribution.

"Subscription Agreement" shall mean the Agreement, attached to the Prospectus as Appendix B, pursuant to which an Investor subscribes to Units in the Partnership.

"Substituted Investor Partner" shall mean any Person admitted to the Partnership as an Investor Partner pursuant to Section 7.03(c) hereof.

"Treas. Reg." or "Regulation" shall mean the income tax regulations promulgated under the Code, as such regulations may be amended from time to time (including corresponding provisions of succeeding regulations).

"Unit" shall mean an undivided interest of the Investor Partners in the aggregate interest in the capital and profits of the Partnership. Each Unit represents Capital Contributions of $20,000 to the Partnership.

"Working Interest" shall mean an interest in an oil and gas leasehold which is subject to some portion of the costs of development, operation, or maintenance.

Capitalization

j. Capital Contributions of the Managing General Partner and Initial Limited Partner.

(a) On or before the Offering Termination Date, the Managing General Partner shall make a Capital Contribution in cash to the Partnership of an amount equal to not less than 24.4% of the aggregate Capital Contributions of the Investor Partners.

(b) The Managing General Partner shall pay all Lease and tangible drilling costs as well as all Intangible Drilling Costs in excess of such costs paid by the Investor Partners with respect to the Partnership; to the extent that such costs are greater than the Managing General Partner's Capital Contribution set forth in the previous subsection, the Managing General Partner shall make such additional contributions in cash to the Partnership equal to such additional Costs; in the event of such additional Capital Contribution, the Managing General Partner's share of profits and losses and distributions shall equal the percentage arrived at by dividing the Managing General Partner's Capital Contribution by the total well costs, excluding the Managing General Partner's Drilling Compensation, except that such percentage may be revised by Sections 3.02 and 4.02.

(c) In consideration of making its Capital Contribution as reflected in this Section 2.01(a), becoming a General Partner, subjecting its assets to the liabilities of the Partnership, and undertaking other obligations as herein set forth, the Managing General Partner shall receive the interest in the Partnership allocated in Article III hereof.

(d) The Initial Limited Partner shall contribute $100 in cash to the capital of the Partnership. Upon the earlier of the conversion of an Additional General Partner's interest into a Limited Partner's interest or the admission of a Limited Partner to the Partnership, the Partnership shall redeem in full, without interest or deduction, the Initial Limited Partner's Capital Contribution, and the Initial Limited Partner shall cease to be a Partner.

k. Capital Contributions of the Investor Partners.

a. Upon execution of this Agreement, each Investor Partner (whose names and addresses and number of Units to which Subscribed are set forth in Exhibit A) shall contribute to the capital of the Partnership the sum of $20,000 for each Unit purchased. The minimum subscription by an Investor Partner is one-quarter Unit ($5,000).

b. The contributions of the Investor Partners pursuant to subsection 2.02(a) hereof shall be in cash or by check subject to collection.

c. Until the Offering Termination Date and until such subsequent time as the contributions of the Investor Partners are invested in accordance with the provisions of the Prospectus, all monies received from persons subscribing as Investor Partners (i) shall continue to be the property of the investor making such payment, (ii) shall be held in escrow for such investor in the manner and to the extent provided in the Prospectus, and (iii) shall not be commingled with the personal monies or become an asset of the Managing General Partner or the Partnership.

d. Upon the original sale of Units by the Partnership, subscribers shall be admitted as Partners no later than 15 days after the release from the escrow account of the Capital Contributions to the Partnership, in accordance with the terms of the Prospectus; subscriptions shall be accepted or rejected by the Partnership within 30 days of their receipt; if rejected, all subscription monies shall be returned to the subscriber forthwith.

e. Except as provided in Section 4.03 hereof, any proceeds of the offering of Units for sale pursuant to the Prospectus not used, committed for use, or reserved as operating capital in the Partnership's operations within one year after the closing of such offering shall be distributed pro rata to the Investor Partners as a return of capital and the Managing General Partner shall reimburse such Investors for selling expenses, management fees, and offering expenses allocable to the return of capital.

f. Until proceeds from the public offering are invested in the Partnership's operations, such proceeds may be temporarily invested in income producing short-term, highly liquid investments, where there is appropriate safety of principal, such as U.S. Treasury Bills. Any such income shall be allocated pro rata to the Investor Partners providing such capital contributions.

l. Additional Contributions. Except as otherwise provided in this Agreement, no Investor Partner shall be required or obligated (a) to contribute any capital to the Partnership other than as provided in Section 2.02 hereof, or (b) to lend any funds to the Partnership. No interest shall be paid on any capital contributed to the Partnership pursuant to this Article II and, except as otherwise provided herein, no Partner, other than the Initial Limited Partner as authorized herein, may withdraw his Capital Contribution. The Units are nonassessable; however, General Partners are liable, in addition to their Capital Contributions, for Partnership obligations and liabilities represented by their ownership of interests as general partners, in accordance with West Virginia law.

Capital Accounts and Allocations

m. Capital Accounts.

a. General. A separate Capital Account shall be established and maintained for each Partner on the books and records of the Partnership. Capital Accounts shall be maintained in accordance with Treas. Reg. Section 1.704-1(b) and any inconsistency between the provisions of this Section 3.01 and such regulation shall be resolved in favor of the regulation. In the event the Managing General Partner shall determine that it is prudent to modify the manner in which the Capital Accounts, or any debits or credits thereto (including, without limitation, debits or credits relating to liabilities that are secured by contributed or distributed property or that are assumed by the Partnership of the Partners), are computed in order to comply with such regulations, the Managing General Partner may make such modification, provided that it is not likely to have a material effect on the amounts distributable to any Partner pursuant to Section 9.03 hereof upon the dissolution of the Partnership. The Managing General Partner also shall (i) make any adjustments that are necessary or appropriate to maintain equality between the Capital Accounts of the Partners and the amount of Partnership capital reflected on the Partnership's balance sheet, as computed for book purposes, in accordance with Treas. Reg. Section 1.704-1(b)(2)(iv)(q), and (ii) make any appropriate modifications in the event unanticipated events might otherwise cause this Agreement not to comply with Treas. Reg. Section 1.704-1(b).

b. Increases to Capital Accounts. Each Partner's Capital Account shall be credited with (i) the amount of money contributed by him to the Partnership; (ii) the amount of any Partnership liabilities that are assumed by him (within the meaning of Treas. Reg. Section 1.704-1(b)(2)(iv)(c)), but not by increases in his share of Partnership liabilities within the meaning of Code Section 752(a); (iii) the Gross Asset Value of property contributed by him to the Partnership (net of liabilities securing such contributed property that the Partnership is considered to assume or take subject to under Code Section 752); and (iv) allocations to him of Partnership Profits (or items thereof), including income and gain exempt from tax and Income and gain described in Treas. Reg. Section 1.704-1(b)(2)(iv)(g) (relating to adjustments to reflect book value).

c. Decreases to Capital Accounts. Each Partner's Capital Account shall be debited with (i) the amount of money distributed to him by the Partnership; (ii) the amount of his individual liabilities that are assumed by the Partnership (other than liabilities described in Treas. Reg. Section 1.704-1(b)(2)(iv)(b)(2) that are assumed by the Partnership and other than decreases in his share of Partnership liabilities within the meaning of Code Section 752(b)); (iii) the Gross Asset Value of property distributed to him by the Partnership (net of liabilities securing such distributed property that he is considered to assume or take subject to under Code Section 752); (iv) allocations to him of expenditures of the Partnership not deductible in computing Partnership taxable income and not properly chargeable to Capital Account (as described in Code Section 705(a)(2)(B)), and (v) allocations to him of Partnership Losses (or item thereof), including loss and deduction described in Treas. Reg. Section 1.704-1(b)(2)(iv)(g) (relating to adjustments to reflect book value), but excluding items described in (iv) above and excluding loss or deduction described in Treas. Reg. Section 1.704-1(b)(4)(iii) (relating to excess percentage depletion).

d. Adjustments to Capital Accounts Related to Depletion.

1. Solely for purposes of maintaining the Capital Accounts, each year the Partnership shall compute (in accordance with Treas. Reg. Section 1.704-1(b)(2)(iv)(k)) a simulated depletion allowance for each oil and gas property using that method, as between the cost depletion method and the percentage depletion method (without regard to the limitations of Code Section 613A(c)(3) which theoretically could apply to any Partner), which results in the greatest simulated depletion allowance. The simulated depletion allowance with respect to each oil and gas property shall reduce the Partners' Capital Accounts in the same proportion as the Partners were allocated adjusted basis with respect to such oil and gas property under Section 3.03(a) hereof. In no event shall the Partnership's aggregate simulated depletion allowance with respect to an oil and gas property exceed the Partnership's adjusted basis in the oil and gas property (maintained solely for Capital Account purposes).

2. Upon the taxable disposition of an oil and gas property by the Partnership, the Partnership shall determine the simulated (hypothetical) gain or loss with respect to such oil and gas property (solely for Capital Account purposes) by subtracting the Partnership's simulated adjusted basis for the oil and gas property (maintained solely for Capital Account purposes) from the amount realized by the Partnership upon such disposition. Simulated adjusted basis shall be determined by reducing the adjusted basis by the aggregate simulated depletion charged to the Capital Accounts of all Partners in accordance with Section 3.01(d)(i) hereof. The Capital Accounts of the Partners shall be adjusted upward by the amount of any simulated gain on such disposition in proportion to such Partners' allocable share of the portion of total amount realized from the disposition of such property that exceeds the Partnership's simulated adjusted basis in such property. The Capital Accounts of the Partners shall be adjusted downward by the amount of any simulated loss in proportion to such Partners' allocable shares of the total amount realized from the disposition of such property that represents recovery of the Partnership's simulated adjusted basis in such property.

e. Restoration of Negative Capital Accounts. Except as otherwise provided in this Agreement, neither an Investor Partner nor the Initial Limited Partner shall be obligated to the Partnership or to any other Partner to restore any negative balance in his Capital Account. The Managing General Partner shall be obligated to restore the deficit balance in its Capital Account.

n. Allocation of Profits and Losses.

a. General. Except as provided in this Section 3.02 or in Section 2.01(a) and Section 3.03 hereof, Profits and Losses during the production phase of the Partnership shall be allocated 75% to the Investor Partners and 25% to the Managing General Partner; provided, that if the Managing General Partner's share of cash distributions is revised pursuant to Section 4.02, the allocations of Profits and Losses of the Partnership shall be allocated to reflect such revision. Notwithstanding the above allocations, the following special allocations shall be employed:

1. irrespective of any revisions effected by Section 2.01(a) or Section 4.02, IDC and recapture of IDC shall be allocated 100% to the Investor Partners and 0% to the Managing General Partner, except as otherwise provided in the following clause; however, in the event that a portion of the Capital Contribution of the Managing General Partner is utilized for IDC, as provided by Section 2.01(a)(ii), then IDC and recapture of IDC shall be allocated to the Investor Partners and the Managing General Partner in a percentage equal to their respective contribution to IDC;

2. irrespective of any revisions effected by Section 2.01(a) or Section 4.02, the following provisions shall apply: Organization and Offering Costs net of commissions, due diligence expenses and wholesaling fees payable to the dealer-manager and the soliciting dealers shall be paid by the Managing General Partner; such commissions, due diligence expenses and wholesaling fees payable to the dealer manager and the soliciting dealers shall be allocated 100% to the Investor Partners and 0% to the Managing General Partner; except that Organization and Offering Costs in excess of 10½% of Subscriptions shall be allocated 100% to the Managing General Partner and 0% to the Investor Partners;

3. irrespective of any revisions effected by Section 2.01(a) or Section 4.02, the Management Fee shall be allocated 100% to the Investor Partners and 0% to the Managing General Partner;

4. irrespective of any revisions effected by Section 2.01(a) or Section 4.02, Costs of Leases and Costs of tangible equipment, including depreciation or cost recovery benefits, shall be allocated 0% to the Investor Partners and 100% to the Managing General Partner and revenues from the sale of equipment shall be allocated 75% to the Investor Partners and 25% to the Managing General Partner;

5. Drilling and Completion Costs shall be allocated 75% to the Investor Partners and 25% to the Managing General Partner;

6. Direct Costs and Operating Costs shall be allocated 75% to the Investor Partners and 25% to the Managing General Partner; and

7. irrespective of any revisions effected by Section 2.01(a) or Section 4.02, Administrative Costs shall be borne 100% by and allocated 100% to the Managing General Partner.

b. Capital Account Deficits. Notwithstanding anything to the contrary in Section 3.02(a), no Investor Partner shall be allocated any item to the extent that such allocation would create or increase a deficit in such Investor Partner's Capital Account.

1. Obligations to Restore. For purposes of this Section 3.02(b), in determining whether an allocation would create or increase a deficit in a Partner's Capital Account, such Capital Account shall be reduced for those items described in Treas. Reg. Section 1.704-1(b)(2)(ii)(d)(4), (5), and (6) and shall be increased by any amounts which such Partner is obligated to restore or is deemed obligated to restore pursuant to the penultimate sentences of Treas. Reg. Sections 1.704-2(g)(1) and 1.704-2(i)(5). Further, such Capital Accounts shall otherwise meet the requirements of Treas. Reg. Section 1.704-1(b)(2)(ii)(d).

2. Reallocations. Any loss or deduction of the Partnership, the allocation of which to any Partner is prohibited by this Section 3.02(b), shall be reallocated to those Partners not having a

deficit in their Capital Accounts (as adjusted in Section 3.02(b)(i)) in the proportion that the positive balance of each such Partner's adjusted Capital Account bears to the aggregate balance of all such Partners' adjusted Capital Accounts, with any remaining losses or deductions being allocated to the Managing General Partner.

3. Qualified Income Offset. In the event any Investor Partner unexpectedly receives any adjustments, allocations, or distributions described in Treas. Reg. Section 1.704-1(b)(2)(ii)(d)(4), (5), or (6), items of Partnership income and gain shall be specifically allocated to such Partner in an amount and manner sufficient to eliminate (to the extent required by the Regulations) the total of the deficit balance in his Capital Account (as adjusted in Section 3.02(b)(i)) created by such adjustments, allocations, or distributions, provided that an allocation pursuant to this Section 3.02(b)(iii) shall be made if and only to the extent that such Partner would have a deficit in his Capital Account (as adjusted in Section 3.02(b)(i)) after all other allocations provided for in this Section 3 have been tentatively made as if this Section 3.02(b)(iii) were not in the Agreement.

4. Gross Income Allocations. In the event an Investor Partner has a deficit Capital Account at the end of any Partnership fiscal year which is in excess of the sum of (i) the amount such Partner is obligated to restore pursuant to any provision of this Agreement and (ii) the amount such Partner is deemed to be obligated to restore pursuant to the penultimate sentences of Treas. Reg. Sections 1.704-2(g)(1) and 1.704-2(i)(5), such Partner shall be specially allocated items of Partnership income and gain in the amount of such excess as quickly as possible, provided that an allocation pursuant to this Section 3.02(b)(iv) shall be made only if and to the extent that such Partner would have a deficit Capital Account in excess of such sum after all other allocations provided for in this Section 3 have been made as if Section 3.02(b)(iii) hereof and this Section 3.02(b)(iv) were not in the Agreement.

c. Minimum Gain Chargeback. Notwithstanding any other provision of this Section 3.02, if there is a net decrease in Partnership Minimum Gain during any taxable year, pursuant to Treas. Reg. Section 1.704-2(f)(1), all Partners shall be allocated items of partnership income and gain for that year equal to that partner's share of the net decrease in Partnership Minimum Gain (within the meaning of Treas. Reg. Section 1.704-2(g)(2)). Notwithstanding the preceding sentence, no such chargeback shall be made to the extent one or more of the exceptions and/or waivers provided for in Treas. Reg. Section 1.704-2(f)(2)-(5) applies. Allocations pursuant to the previous sentence shall be made in proportion to the respective amounts required to be allocated to each Partner pursuant thereto. The items to be so allocated shall be determined in accordance with Treas. Reg. Section 1.704-2(f)(6). This Section 3.02(c) is intended to comply with the minimum gain chargeback requirement in such Section of the Regulations and shall be interpreted consistently therewith. To the extent permitted by such Section of the Regulations and for purposes of this Section 3.02(c) only, each Partner's Capital Account (as adjusted in Section 3.02(b)(i)) shall be determined prior to any other allocations pursuant to this Section 3 with respect to such tax year and without regard to any net decrease in Partner Minimum Gain during such fiscal year.

d. Partner Minimum Gain Chargeback. Notwithstanding any other provision of this Section 3 except Section 3.02(c), if there is a net decrease in Partner Minimum Gain attributable to a Partner Nonrecourse Debt during any Partnership fiscal year, rules similar to those contained in Section 3.02(c) shall apply in a manner consistent with Treas. Reg. Section 1.704-2(i)(4). This Section 3.02(d) is intended to comply with the minimum gain chargeback requirement in such Section of the Regulations and shall be interpreted consistently therewith. Solely for purposes of this Section 3.02(d), each Person's Capital Account deficit (as so adjusted) shall be determined prior to any other allocations pursuant to this Section 3 with respect to such fiscal year, other than allocations pursuant to Section 3.02(c) hereof.

e. Nonrecourse Deductions. Nonrecourse Deductions for any fiscal year or other period shall be specially allocated to the Partners (in proportion to their Units), in accordance with Treas. Reg. Section 1.704-2.

f. Partner Nonrecourse Deductions. Any Partner Nonrecourse Deductions for any fiscal year or other period shall be specially allocated to the Partner who bears the economic risk of loss with respect to the Partner Nonrecourse Debt to which such Partner Nonrecourse Deductions are attributable in accordance with Treas. Reg. Section 1.704-2(i).

g. Code Section 754 Adjustments. To the extent an adjustment to the adjusted tax basis of any Partnership asset pursuant to Code Section 734(b) or 743(b) is required, pursuant to Treas. Reg. Section 1.704-1(b)(2)(iv)(m), to be taken into account in determining Capital Accounts, the amount of such adjustment to the Capital Accounts shall be treated as an item of gain (if the adjustment increases the basis of the asset) or loss (if the adjustment decreases such basis) and such gain or loss shall be specially allocated to the Partners in a manner consistent with the manner in which their Capital Accounts are required to be adjusted pursuant to such Section of the Regulations.

h. Curative Allocations.

1. The "Regulatory Allocations" consist of the "Basic Regulatory Allocations," as defined in Section 3.02(h)(ii) hereof, the "Nonrecourse Regulatory Allocations," as defined in Section 3.02(h)(iii) hereof, and the "Partner Nonrecourse Regulatory Allocations," as defined in Section 3.02(h)(iv) hereof.

2. The "Basic Regulatory Allocations" consist of allocations pursuant to Section 3.02(b)(ii), (iii), and (iv) hereof. Notwithstanding any other provision of this Agreement, other than the Regulatory Allocations, the Basic Regulatory Allocations shall be taken into account in allocating items of income, gain, loss, and deduction among the Partners so that, to the extent possible, the net amount of such allocations of other items and the Basic Regulatory Allocations to each Partner shall be equal to the net amount that would have been allocated to each such Partner if the Basic Regulatory Allocations had not occurred. For purposes of applying the foregoing sentence, allocations pursuant to this Section 3.02(h)(ii) shall only be made with respect to allocations pursuant to Section 3.02(g) hereof to the extent the Managing General Partner reasonably determines that such allocations will otherwise be inconsistent with the economic agreement among the parties to this Agreement.

3. The "Nonrecourse Regulatory Allocations" consist of all allocations pursuant to Section 3.02(c) and 3.02(e) hereof. Notwithstanding any other provision of this Agreement, other than the Regulatory Allocations, the Nonrecourse Regulatory Allocations shall be taken into account in allocating items of income, gain, loss, and deduction among the Partners so that, to the extent possible, the net amount of such allocations of other items and the Nonrecourse Regulatory Allocations to each Partner shall be equal to the net amount that would have been allocated to each Partner if the Nonrecourse Regulatory Allocations had not occurred. For purposes of applying the foregoing sentence (i) no allocations pursuant to this Section 3.02(h)(iii) shall be made prior to the Partnership fiscal year during which there is a net decrease in Partnership Minimum Gain, and then only to the extent necessary to avoid any potential economic distortions caused by such net decrease in Partnership Minimum Gain, and (ii) allocations pursuant to this Section 3.02(h)(iii) shall be deferred with respect to allocations pursuant to Section 3.02(e) hereof to the extent the Managing General Partner reasonably determines that such allocations are likely to be offset by subsequent allocations pursuant to Section 3.02(c).

4. The "Partner Nonrecourse Regulatory Allocations" consist of all allocations pursuant to Sections 3.02(d) and 3.02(f) hereof. Notwithstanding any other provision of this Agreement,

other than the Regulatory Allocations, the Partner Nonrecourse Regulatory Allocations shall be taken into account in allocating items of income, gain, loss, and deduction among the Partners so that, to the extent possible, the net amount of such allocations of other items and the Partner Nonrecourse Regulatory Allocations to each Partner shall be equal to the net amount that would have been allocated to each such Partner if the Partner Nonrecourse Regulatory Allocations had not occurred. For purposes of applying the foregoing sentence (i) no allocations pursuant to this Section 3.02(h)(iv) shall be made with respect to allocations pursuant to Section 3.02(f) relating to a particular Partner Nonrecourse Debt prior to the Partnership fiscal year during which there is a net decrease in Partner Minimum Gain attributable to such Partner Nonrecourse Debt, and then only to the extent necessary to avoid any potential economic distortions caused by such net decrease in Partner Minimum Gain, and (ii) allocations pursuant to this Section 3.02(h)(iv) shall be deferred with respect to allocations pursuant to Section 3.02(f) hereof relating to a particular Partner Nonrecourse Debt to the extent the Managing General Partner reasonably determines that such allocations are likely to be offset by subsequent allocations pursuant to Section 3.02(d) hereof.

5. The Managing General Partner shall have reasonable discretion with respect to each Partnership fiscal year, to apply the provisions of Sections 3.02(h)(ii), (iii), and (iv) hereof among the Partners in a manner that is likely to minimize such economic distortions.

i. Other Allocations. Except as otherwise provided in this Agreement, all items of Partnership income, loss, deduction, and any other allocations not otherwise provided for shall be divided among the Unit Holders in the same proportions as they share Profits or Losses, as the case may be, for the year.

j. Agreement to be Bound. The Partners are aware of the income tax consequences of the allocations made by this Section 3.02 and hereby agree to be bound by the provisions of this Section 3.02 in reporting their shares of Partnership income and loss for income tax purposes.

k. Excess Nonrecourse Liabilities. Solely for purposes of determining a Partner's proportionate share of the "excess nonrecourse liabilities" of the Partnership within the meaning of Treas. Reg. Section 1.752-3(a)(3), the Partners' interests in Partnership profits are as follows: Investor Partners, 75% (in proportion to their Units) and the Managing General Partner, 25%.

l. Allocation Variations. The Managing General Partner shall have the authority to vary allocations to preserve and protect the intention of the Partners as follows:

1. It is the intention of the Partners that each Partner's distributive share of income, gain, loss, deduction or credit (or any item thereof) shall be determined and allocated in accordance with this Article 3 to the fullest extent permitted by Code Section 704(b). In order to preserve and protect the allocations provided for in this Article 3, the Managing General Partner shall have the authority to allocate income, gain, loss, deduction or credit (or any item thereof) arising in any year differently than that expressly provided for in this Article 3, if and to the extent that determining and allocating income, gain, loss, deduction or credit (or any item thereof) in the manner expressly provided for in this Article 3 would cause the allocations of each Partner's distributive share of income, gain, loss, deduction or credit (or any item thereof) not to be permitted by Code Section 704(b) and the Regulations promulgated thereunder. Any allocation made pursuant to this Section 3.02(l) shall be deemed to be a complete substitute for any allocation otherwise expressly provided for in this Article 3, and no amendment of this Agreement or further consent of any Partner shall be required therefor.

2. In making any such allocation (the "new allocation") under this Section 3.02(l) the Managing General Partner shall be authorized to act only after having been advised by the

Partnership's accountants and/or counsel that, under Code Section 704(b) and the Regulations thereunder, (i) the new allocation is necessary, and (ii) the new allocation is the minimum modification of the allocations otherwise expressly provided for in this Article 3 which is necessary in order to assure that, either in the then current year or in any preceding year, each Partner's distributive share of income, gain, loss, deduction or credit (or any item thereof) is determined and allocated in accordance with this Article 3 to the fullest extent permitted by Code Section 704(b) and the Regulations thereunder.

3. If the Managing General Partner is required by this Section 3.02(l) to make any new allocation in a manner less favorable to the Investor Partners than is otherwise expressly provided for in this Article 3, then the Managing General Partner shall have the authority, only after having been advised by the Partnership's accountants and/or counsel that they are permitted by Code Section 704(b), to allocate income, gain, loss, deduction or credit (or any item thereof) arising in later years in such a manner as will make the allocations of income, gain, loss, deduction or credit (or any item thereof) to the Investor Partners as comparable as possible to the allocations otherwise expressly provided for or contemplated by this Article 3.

4. Any new allocation made by the Managing General Partner under this Section 3.02(l) in reliance upon the advice of the Partnership's accountants and/or counsel shall be deemed to be made pursuant to the fiduciary obligation of the Managing General Partner to the Partnership and the Investor Partners, and no such new allocation shall give rise to any claim or cause of action by any Investor Partner.

m. <u>Tax Allocations: Code Section 704(c)</u>. In accordance with Code Section 704(c) and the Regulations thereunder, income, gain, loss, and deduction with respect to any property contributed to the capital of the Partnership shall, solely for tax purposes, be allocated among the Partners so as to take account of any variation between the adjusted basis of such property to the Partnership for federal income tax purposes and its initial Gross Asset Value (computed in accordance with Section 1.08(s)(1).

In the event the Gross Asset Value of any Partnership asset is adjusted pursuant to Section 1.08(s)(1) hereof, subsequent allocations of income, gain, loss, and deduction with respect to such asset shall take account of any variation between the adjusted basis of such asset for federal income tax purposes and its Gross Asset Value in the same manner as under Code Section 704(c) and the Regulations thereunder.

Any elections or other decisions relating to such allocations shall be made by the Managing General Partner in any manner that reasonably reflects the purpose and intention of this Agreement. Allocations pursuant to this Section 3.02(m) are solely for purposes of federal, state, and local taxes and shall not affect, or in any way be taken into account in computing, any Person's Capital Account or share of Profits, Losses, other items, or distributions pursuant to any provision of this Agreement.

o. Depletion.

a. The depletion deduction with respect to each oil and gas property of the Partnership shall be computed separately for each Partner in accordance with Code Section 613A(c)(7)(D) for Federal income tax purposes. For purposes of such computation, the adjusted basis of each oil and gas property shall be allocated in accordance with the Partners' interests in the capital of the Partnership. Among the Investor Partners, such adjusted basis shall be apportioned among them in accordance with the number of Units held.

b. Upon the taxable disposition of an oil or gas property by the Partnership, the amount realized from and the adjusted basis of such property shall be allocated among the Partners (for purposes of calculating their individual gain or loss on such disposition for Federal income tax purposes) as follows:

1. The portion of the total amount realized upon the taxable disposition of such property that represents recovery of its simulated adjusted tax basis therein (as calculated pursuant to Section 3.01(d) hereof) shall be allocated to the Partners in the same proportion as the aggregate adjusted basis of such property was allocated to such Partners (or their predecessors in interest) pursuant to Section 3.03(a) hereof; and

2. The portion of the total amount realized upon the taxable disposition of such property that represents the excess over the simulated adjusted tax basis therein shall be allocated in accordance with the provisions of Section 3.02 hereof as if such gain constituted an item of Profit.

p. Apportionment Among Partners.

a. Except as otherwise provided in this Agreement, all allocations and distributions to the Investor Partners shall be apportioned among them pro rata based on Units held by the Partners.

b. For purposes of Section 3.04(a) hereof, an Investor Partner's pro rata share in Units shall be calculated as of the end of the taxable year for which such allocation has been made; provided, however, that if a transferee of a Unit is admitted as an Investor Partner during the course of the taxable year, the apportionment of allocations and distributions between the transferor and transferee of such Unit shall be made in the manner provided in Section 3.04(c) hereof.

c. If, during any taxable year of the Partnership, there is a change in any Partner's interest in the Partnership, each Partner's allocation of any item of income, gain, loss, deduction, or credit of the Partnership for such taxable year, other than "allocable cash basis items" shall be determined by taking into account the varying interests of the Partners pursuant to such method as is permitted by Code Section 706(d) and the regulations thereunder. Each Partner's share of "allocable cash basis items" shall be determined in accordance with Code Section 706(d)(2) by (i) assigning the appropriate portion of each 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. "Allocable cash basis item" shall have the meaning ascribed to it by Code Section 706(d)(2)(B) and the regulations thereunder.

Distributions

q. Time of Distribution. Cash available for distribution shall be determined by the Managing General Partner. The Managing General Partner shall distribute, in its discretion, such cash deemed available for distribution, but such distributions shall be made not less frequently than quarterly.

r. Distributions.

a. Except as otherwise provided below and in Section 2.01(a), all distributions (other than those made to wind up the Partnership in accordance with Section 9.03 hereof) shall be made 75% to the Investor Partners and 25% to the Managing General Partner. If the performance standard as defined below in subsection (b) is not fulfilled by a particular Partnership, that Partnership's sharing arrangement shall be modified, as set forth herein, for up to a ten-year period commencing eight months after the closing date of that Partnership and ending ten years following such closing date.

b. The performance standard shall be as follows:

1. If the Average Annual Rate of Return, as defined below, to the Investor Partners is less than 12.5% of their Subscriptions, the allocation rate of all items of profit and loss and cash available for distribution for Investor Partners shall be increased by ten percentage points above the then-current sharing arrangements for Investor Partners and the allocation rate with respect to such items for the Managing General Partner will be decreased by ten percentage points below the then-current sharing arrangements for the Managing General Partner, until the Average Annual Rate of Return shall have increased to 12.5% or more, or until ten years and eight months shall have expired from the closing date of the Partnership, whichever event shall occur sooner.

2. Average Annual Rate of Return for purposes of this sharing arrangement shall be defined as (1) the sum of cash distributions and estimated initial tax savings of 25% of Subscriptions, realized for a $10,000 investment in the Partnership, divided by (2) $10,000 multiplied by the number of years (less eight months) which have elapsed since the closing of the Partnership.

c. The Partnership shall not require that Investor Partners reinvest their share of cash available for distribution in the Partnership. In no event shall funds be advanced or borrowed for purposes of distributions, if the amount of such distributions would exceed the Partnership's accrued and received revenues for the previous four quarters, less paid and accrued operating costs with respect to such revenues. The determination of such revenues and costs shall be made in accordance with generally accepted accounting principles, consistently applied. Cash distributions from the Partnership to the Managing General Partner shall only be made in conjunction with distributions to Investor Partners and only out of funds properly allocated to the Managing General Partner's account.

s. Capital Account Deficits. No distributions shall be made to any Investor Partner to the extent such distribution would create or increase a deficit in such Partner's Capital Account (as adjusted in Section 3.02(b)(i)). Any distribution which is hereby prohibited shall be made to those Partners not having a deficit in their Capital Accounts (as adjusted in Section 3.02(b)(i)) in the proportion that the positive balance of each such Partner's adjusted Capital Account bears to the aggregate balance of all such Partners' adjusted Capital Accounts. Any cash available for distribution remaining after reduction of all adjusted Capital Accounts to zero shall be distributed to the Managing General Partner.

t. Liability Upon Receipt of Distributions.

a. If a Partner has received a return of any part of his Capital Contribution without violation of the Partnership Agreement or the Act, he is liable to the Partnership for a period of one year thereafter for the amount of such returned contribution, but only to the extent necessary to discharge the Partnership's liabilities to creditors who extended credit to the Partnership during the period the Capital Contribution was held by the Partnership.

b. If a Partner has received a return of any part of his Capital Contribution in violation of either the Partnership Agreement or the Act, he is liable to the Partnership for a period of six years thereafter for the amount of the Capital Contribution wrongfully returned.

c. A Partner receives a return of his Capital Contribution to the extent that the distribution to him reduces his share of the fair value of the net assets of the Partnership below the value, as set forth in the records required to be kept by West Virginia law, of his Capital Contribution which has not been distributed to him.

u. Management. The Managing General Partner shall conduct, direct, and exercise full and exclusive control over all activities of the Partnership. Investor Partners shall have no power over the conduct of the affairs of the Partnership or otherwise commit or bind the Partnership in any manner. The Managing General Partner shall manage the affairs of the Partnership in a prudent and businesslike fashion and shall use its best efforts to carry out the purposes and character of the business of the Partnership.

v. Conduct of Operations.

a. • The Managing General Partner shall establish a program of operations for the Partnership which shall be in conformance with the following policies: (x) no less than 90% of the Capital Contributions net of Organization and Offering Costs and the Management Fee shall be applied to drilling and completing Development Wells; (y) the Partnership shall drill all of its wells in West Virginia, Ohio, Pennsylvania, Colorado, New York, Kentucky, Michigan, Indiana, Kansas, Montana, South Dakota, Tennessee, Utah, Wyoming, Nebraska, North Dakota, Alabama, Texas and/or Oklahoma; and (z) the Prospects will be acquired pursuant to an arrangement whereby the Partnership will acquire up to 100% of the Working Interest, subject to landowners' royalty interests and the royalty interests payable to unaffiliated third parties in varying amounts, provided that the average of the maximum royalty interests for all Prospects of the Partnership shall not exceed 25%.

1. The Investor Partners agree to participate in the Partnership's program of operations as established by the Managing General Partner; provided, that no well drilled to the point of setting casing need be completed if, in the Managing General Partner's opinion, such well is unlikely to be productive of oil or gas in quantities sufficient to justify the expenditures required for well completion. The Partnership may participate with others in the drilling of wells and it may enter into joint ventures, partnerships, or other such arrangements.

b. All transactions between the Partnership and the Managing General Partner or its Affiliates shall be on terms no less favorable than those terms which could be obtained between the Partnership and independent third parties dealing at arm's-length, subject to the provisions of Section 5.07 hereof.

c. The Partnership shall not participate in any joint operations on any co-owned Lease unless there has been acquired or reserved on behalf of the Partnership the right to take in kind or separately dispose of its proportionate share of the oil and gas produced from such Lease exclusive of production which may be used in development and production operations on the Lease and production unavoidably lost, and, if the Managing General Partner is the operator of such Lease, the Managing General Partner has entered into written agreements with every other person or entity owning any working or operating interest reserving to such person or entity a similar right to take in-kind, unless, in the opinion of counsel to the Partnership, the failure to reserve such right to take in-kind will not result in the Partnership being treated as a member of an association taxable as a corporation for Federal income tax purposes.

d. The relationship of the Partnership and the Managing General Partner (or any Affiliate retaining or acquiring an interest) as co-owners in Leases, except to the extent superseded by an Operating Agreement consistent with the preceding paragraph and except to the extent inconsistent with this Partnership Agreement, shall be governed by the AAPL Form 610 Model Operating Agreement-1982, with a provision reserving the right to take production in-kind, naming the Managing General Partner as operator and the Partnership as a nonoperator, and with the accounting procedure to govern as the accounting procedures under such Operating Agreements.

e. The Managing General Partner is generally expected to act as the operator of Partnership wells, and the Managing General Partner may designate such other persons as it deems appropriate to conduct the actual drilling and producing operations of the Partnership. If the Managing General Partner retains another person as operator, the contract of retention shall provide that the new operator will have capabilities that are comparable to those of the Managing General Partner, including the availability of technical expertise and adequate response time.

f. As operator of Partnership wells, the Managing General Partner or its Affiliates shall receive per-well charges for each producing well based on the Working Interest acquired by the Partnership. These per-well charges shall be subject to annual adjustment beginning January 1, 2006 [with respect to Partnerships designated as "PDC 2004- Limited Partnership," January 1, 2007 with respect to Partnerships designated as "PDC 2005- Limited Partnership" and January 1, 2008 with respect to Partnerships designated as "PDC 2006- Limited Partnership"] as provided in the accounting procedures of the operating agreements.

g. The Managing General Partner shall drill wells pursuant to drilling contracts with the Partnership at the lesser of cost or competitive prices and terms in the geographic area of operations. The Managing General Partner’s Drilling Compensation shall be its compensation for serving as managing general partner and operator and for contributing its leases at cost.

h. The Managing General Partner shall be reimbursed by the Partnership for Direct Costs. The Managing General Partner shall not be reimbursed for any Administrative Costs. All other expenses shall be borne by the Partnership.

i. The Managing General Partner and its Affiliates may enter into other transactions (embodied in a written contract) with the Partnership during production operations, such as providing services, supplies, and equipment, and shall be entitled to compensation for such services at prices and on terms that are competitive in the geographic area of operations.

j. The Partnership shall make no loans to the Managing General Partner or any Affiliate thereof.

k. The Partnership may borrow funds in furtherance of its operations from the Managing General Partner and/or its Affiliates or from independent persons; if the Managing General Partner or any Affiliate loans or advances funds to the Partnership, the Managing General Partner or Affiliate shall not receive interest on such loan or advancement in excess of its interest costs, nor shall the Managing General Partner or Affiliate receive interest in excess of the amounts which would be charged the Partnership (without reference to the Managing General Partner’s financial abilities or guarantees) by unrelated banks on comparable loans for the same purpose, and the Managing General Partner or Affiliate shall not receive points or other financial charges or fees, regardless of the amount.

l. The funds of the Partnership shall not be commingled with the funds of any other Person.

m. Notwithstanding any provision herein to the contrary, no creditor shall receive, as a result of making any loan, a direct or indirect interest in the profits, capital, or property of the Partnership other than as a secured creditor.

n. The Managing General Partner shall have a fiduciary responsibility for the safekeeping and use of all funds and assets of the Partnership, whether or not in the Managing General Partner's possession or control, and shall not employ or permit another to employ such funds or assets in any manner except for the exclusive benefit of the Partnership.

w. Acquisition and Sale of Leases.

a. To the extent the Partnership does not acquire a full interest in a Lease from the Managing General Partner, the remainder of the interest in such Lease may be held by the Managing General Partner which may either retain and exploit it for its own account or sell or otherwise dispose of all or a part of such remaining interest. Profits from such exploitation and/or disposition shall be for the benefit of the Managing General Partner to the exclusion of the Partnership. Any Leases acquired by the Partnership from the Managing General Partner shall be acquired only at the Managing General Partner's Cost, unless the Managing General Partner shall have reason to believe that Cost is in excess of the fair market value of such property, in which case the price shall not exceed the fair market value. The Managing General Partner shall obtain an appraisal from a qualified independent expert with respect to sales of properties of the Managing General Partner and its Affiliates to the Partnership. Neither the Managing General Partner nor any Affiliate shall acquire or retain any carried, reversionary, or Overriding Royalty Interest on the Lease interests acquired by the Partnership, nor shall the Managing General Partner enter into any farmout arrangements with respect to its retained interest, except as provided in Section 5.05 hereof.

b. The Partnership shall acquire only Leases reasonably expected to meet the stated purposes of the Partnership. No Leases shall be acquired for the purpose of a subsequent sale or farmout unless the acquisition is made after a well has been drilled to a depth sufficient to indicate that such an acquisition would be in the Partnership's best interest.

c. Neither the Managing General Partner nor its Affiliates, except other partnerships sponsored by them, shall purchase any productive properties from the Partnership.

x. Title to Leases.

a. Record title to each Lease acquired by the Partnership may be temporarily held in the name of the Managing General Partner, or in the name of any nominee designated by the Managing General Partner, as agent for the Partnership until a productive well is completed on a Lease. Thereafter, record title to Leases shall be assigned to and placed in the name of the Partnership.

b. The Managing General Partner shall take the necessary steps in its best judgment to render title to the Leases to be assigned to the Partnership acceptable for the purposes of the Partnership. No operation shall be commenced on any Prospect acquired by the Partnership unless the Managing General Partner is satisfied that the undertaking of such operation would be in the best interest of Investor Partners and the Partnership. The Managing General Partner shall be free, however, to use its own best judgment in waiving title requirements and shall not be liable to the Partnership or the Investor Partners for any mistakes of judgment unless such mistakes were made in a manner not in accordance with general industry standards in the geographic area and such mistakes were not the result of negligence by the Managing General Partner; nor shall the Managing General Partner or its Affiliates be deemed to be making any warranties or representations, express or implied, as to the validity or merchantability of the title to any Lease assigned to the Partnership or the extent of the interest covered thereby.

y. Farmouts.

a. No Partnership Lease shall be farmed out, sold, or otherwise disposed of unless the Managing General Partner determines that (i) the Partnership lacks sufficient funds to drill on such Lease and is unable to obtain suitable financing, (ii) the Leases have been downgraded by events occurring after assignment to the Partnership, (iii) drilling on the Leases would result in an excessive concentration of Partnership funds creating, in the Managing General Partner's opinion, undue risk to the Partnership, or (iv) the Managing General Partner, exercising the standard of a prudent operator, determines that the farmout is in the best interests of the Partnership.

b. Farmouts between the Partnership and the Managing General Partner or its Affiliates, including any other affiliated limited partnership, shall be effected on terms deemed fair by the Managing General Partner. The Managing General Partner, exercising the standard of a prudent operator, shall determine that the farmout is in the best interest of the Partnership and the terms of the farmout are consistent with and, in any case, no less favorable to the Partnership than those utilized in the geographic area of operations for similar arrangements. The respective obligations and revenue sharing of all affiliated parties to the transactions shall be substantially the same, and the compensation arrangement or any other interest or right of either the Managing General Partner or its Affiliates shall be substantially the same in each participating partnership or, if different, shall be reduced to reflect the lower compensation arrangement.

z. Release, Abandonment, and Sale or Exchange of Properties. Except as provided elsewhere in this Article V and in Section 6.03, the Managing General Partner shall have full power to dispose of the production and other assets of the Partnership, including the power to determine which Leases shall be released or permitted to terminate, those wells to be abandoned, whether any Lease or well shall be sold or exchanged, and the terms therefor. In the event the Managing General Partner sells, transfers, or otherwise disposes of nonproducing property of the Partnership, the sale, transfer, or disposition shall, to the extent possible, be made at a price which is the higher of the fair market value of the property on the date of the sale, transfer, or disposition or the Cost of such property to the Partnership.

aa. Certain Transactions.

▪ • When the Managing General Partner or an Affiliate (excluding another Program in which the interest of the Managing General Partner or its Affiliates is substantially similar to or less than their interest in the Partnership) sells, transfers or conveys any natural gas, oil or other mineral interests or property to the Partnership, it must, at the same time, sell, transfer or convey to the Partnership an equal proportionate interest in all its other property in the same Prospect. A Prospect shall be deemed to consist of the drilling or spacing unit on which the well will be drilled by the Partnership, which is the minimum area permitted by state law or local practice on which one well may be drilled, if the following two conditions are met:

the geological feature to which the well will be drilled contains Proved Reserves, and

the drilling or spacing unit protects against drainage.

With respect to a natural gas or oil Prospect located in Colorado which a well will be drilled by the Partnership to test the Codell, J-sand, Dakota, Niobrara or D-sand formations in Wattenberg Field in Adams or Weld Counties, Colorado, or for a well drilled to test the Mesa Verde formation in Garfield County, Colorado, a Prospect shall be deemed to consist of the drilling and spacing unit if it meets the test in subsection (1) above; additionally, for a period of five years after the drilling of the Partnership Well, neither the Managing General Partner nor its Affiliates may drill any well on any spacing unit adjoining a well drilled for the partnership.

If the Partnership abandons its interest in a well, then the restriction in subsection (2) above will continue for one year following the abandonment.

If the area constituting the Partnership's Prospect is subsequently enlarged to encompass any area in which the Managing General Partner or an Affiliate (excluding another Program in which the interest of the Managing General Partner or its Affiliates is substantially similar to or less than their interest in the Partnership) owns a separate property interest and the activities of the Partnership were material in establishing the existence of Proved Undeveloped Reserves that are attributable to the separate property interest, then the separate property interest or a portion thereof must be sold, transferred, or conveyed to the Partnership as set forth in this section (a).

Notwithstanding the foregoing, Prospects in the Codell, J-sand, Dakota, Niobrara or D-sand formations in Wattenberg Field in Adams or Weld Counties, Colorado, or in the Mesa Verde formation in Garfield County, Colorado, or any other formation or reservoir shall not be enlarged or contracted if the Prospect was limited to the drilling or spacing unit because the well was being drilled to Proved Reserves in the geological formation and the drilling or spacing unit protected against drainage.

If the Managing General Partner or its Affiliates (except another affiliated partnership in which the interest of the Managing General Partner or its Affiliates is identical to or less than their interest in the Partnership) subsequently propose to acquire an interest in a Prospect in which the Partnership possesses an interest or in a Prospect abandoned by the Partnership within one year preceding such proposed acquisition, the Managing General Partner or its Affiliates shall offer an equivalent interest therein to the Partnership; and, if funds, including borrowings, are not available to the Partnership to enable it to consummate a purchase of an equivalent interest in such property and pay the development costs thereof, neither the Managing General Partner nor any of its Affiliates shall acquire such interest or property. The term "abandoned" shall mean the termination, either voluntarily or by operation of the Lease or otherwise, of all of the Partnership's interest in the Prospect. These limitations shall not apply after the lapse of five years from the date of formation of the Partnership.

The geological limits of a Prospect shall be enlarged or contracted on the basis of subsequently acquired geological data that further defines the productive limits of the underlying oil and/or gas reservoir and shall include all of the acreage determined by such subsequent data to be encompassed by such reservoir; further, where the Managing General Partner or Affiliate owns a separate property interest in such enlarged area, such interest shall be sold to the Partnership if the activities of the Partnership were material in establishing the existence of proved undeveloped reserves which are attributable to such separate property interest; provided, however, that the Partnership shall not be required to expend additional funds unless they are available from the initial capitalization of the Partnership or if the Managing General Partner believes it is prudent to borrow for the purpose of acquiring such additional acreage.

The Partnership shall not purchase properties from or sell properties to any other affiliated partnership. This prohibition, however, shall not apply to transactions among affiliated partnerships by which property is transferred from one to another in exchange for the transferee's obligation to conduct drilling activities on such property or to joint ventures among such affiliated partnerships, provided that the respective obligations and revenue sharing of all parties to the transaction are substantially the same and the compensation arrangement or any other interest or right of either the Managing General Partner or its Affiliates is the same in each affiliated partnership, or, if different, the aggregate compensation of the Managing General Partner is reduced to reflect the lower compensation arrangement.

During the existence of the Partnership, and before it has ceased operations, neither the Managing General Partner nor any of its Affiliates (excluding another partnership where the Managing General Partner's or its Affiliates' interest in such partnership is identical to or less than their interest in the Partnership) shall acquire, retain, or drill for their own account any oil and gas interest in any Prospect in which the Partnership possesses an interest, except for transactions whereby the Managing General Partner or such Affiliate acquires or retains a proportionate Working Interest, the respective obligations of the Managing General Partner or the Affiliate and the Partnership are substantially the same after the sale of the interest to the Partnership, and the Managing General Partner's or Affiliate's interest in revenues does not exceed the amount proportionate to its Working Interest.

Any services, equipment, or supplies which the Managing General Partner or an Affiliate furnishes to the Partnership shall be furnished at the lesser of the Managing General Partner's or the Affiliate's Cost or a competitive rate which could be obtained in the geographical area of operations unless the Managing General Partner or any Affiliate is engaged to a substantial extent, as an ordinary and ongoing business, in providing such services, equipment, or supplies to others in the industry, in which event, the services, supplies, or equipment may be provided by such person to the Partnership at prices competitive with those charged by others in the geographical area of operations which would be available to the Partnership. If such entity is not engaged in the business as set forth above, then such compensation, price or rental shall be the cost of such services, equipment or supplies to such entity, or the competitive rate which could be obtained in the area, whichever is less. Any drilling services provided by the Managing General Partner or its Affiliates shall be billed only on a per foot, per day, or per hour rate, or some combination thereof. No turnkey drilling contracts shall be made between the Managing General Partner or its Affiliates and the Partnership. Neither the Managing General Partner nor its Affiliates shall profit by drilling in contravention of its fiduciary obligations to the Partnership. Any such services for which the Managing General

Partner or an Affiliate is to receive compensation shall be embodied in a written contract which precisely describes the services to be rendered and all compensation to be paid.

Advance payments by the Partnership to the Managing General Partner are prohibited, except where necessary to secure tax benefits of prepaid drilling costs. These payments, if any, shall not include nonrefundable payments for completion costs prior to the time that a decision is made that the well or wells warrant a completion attempt.

Neither the Managing General Partner nor its Affiliates shall make any future commitments of the Partnership's production which do not primarily benefit the Partnership, nor shall the Managing General Partner or any Affiliate utilize Partnership funds as compensating balances for the benefit of the Managing General Partner or the Affiliate.

No rebates or give-ups may be received by the Managing General Partner or any of its Affiliates, nor may the Managing General Partner or any Affiliate participate in any reciprocal business arrangements which would circumvent these restrictions.

During a period of five years from the date of formation of the Partnership, if the Managing General Partner or any of its Affiliates proposes to acquire from an unaffiliated person an interest in a Prospect in which the Partnership possesses an interest or in a Prospect in which the Partnership's interest has been terminated without compensation within one year preceding such proposed acquisition, the following conditions shall apply:

a. If the Managing General Partner or the Affiliate does not currently own property in the Prospect separately from the Partnership, then neither the Managing General Partner nor the Affiliate shall be permitted to purchase an interest in the Prospect.

b. If the Managing General Partner or the Affiliate currently owns a proportionate interest in the Prospect separately from the Partnership, then the interest to be acquired shall be divided between the Partnership and the Managing General Partner or the Affiliate in the same proportion as is the other property in the Prospect; provided however, if cash or financing is not available to the Partnership to enable it to consummate a purchase of the additional interest to which it is entitled, then neither the Managing General Partner nor the Affiliate shall be permitted to purchase any additional interest in the Prospect.

If the Partnership acquires property pursuant to a farmout or joint venture from an affiliated program, the Managing General Partner's and/or its Affiliates' aggregate compensation associated with the property and any direct and indirect ownership interest in the property may not exceed the lower of the compensation and ownership interest the Managing General Partner and/or its Affiliates could receive if the property were separately owned or retained by either one of the programs.

Neither the Managing General Partner nor any Affiliate, including affiliated programs, may purchase or acquire any property from the Partnership, directly or indirectly, except pursuant to transactions that are fair and reasonable to the Investor Partners of the Partnership and then subject to the following conditions:

c. A sale, transfer or conveyance, including a farmout, of an undeveloped property from the Partnership to the Managing General Partner or an Affiliate, other than an affiliated program, must be made at the higher of cost or fair market value.

d. A sale, transfer or conveyance of a developed property from the Partnership to the Managing General Partner or an Affiliate, other than an affiliated program in which the interest of the Managing General Partner is substantially similar to or less than its interest in the subject Partnership, shall not be permitted except in connection with the liquidation of the Partnership and then only at fair market value.

e. Except in connection with farmouts or joint ventures made in compliance with Section 5.07(j) above, a transfer of an undeveloped property from the Partnership to an affiliated drilling program must be made at fair market value if the property has been held for more than two years. Otherwise, if the Managing General Partner deems it to be in the best interest of the Partnership, the transfer may be made at cost.

f. Except in connection with farmouts or joint ventures made in compliance with Section 5.07(j) above, a transfer of any type of property from the Partnership to an affiliated production purchase or income program must be made at fair market value if the property has been held for more than six months or there have been significant expenditures made in connection with the property. Otherwise, if the Managing General Partner deems it to be in the best interest of the Partnership, the transfer may be made at cost as adjusted for intervening operations.

If the Partnership participates in other partnerships or joint ventures (multi-tier arrangements), the terms of any such arrangements shall not result in the circumvention of any of the requirements or prohibitions contained in this Partnership Agreement, including the following:

g. there will be no duplication or increase in organization and offering expenses, the Managing General Partner's compensation, Partnership expenses or other fees and costs;

h. there will be no substantive alteration in the fiduciary and contractual relationship between the Managing General Partner and the Investor Partners; and

i. there will be no diminishment in the voting rights of the Investor Partners.

In connection with a proposed Roll-Up, the following shall apply:

An appraisal of all Partnership assets shall be obtained from a competent independent expert. If the appraisal will be included in a prospectus used to offer the securities of a Roll-Up Entity, the appraisal shall be filed with the Securities and Exchange Commission and the Administrator as an exhibit to the registration statement for the offering. The appraisal shall be based on all relevant information, including current reserve estimates prepared by an independent petroleum consultant, and shall indicate the value of the Partnership's assets assuming an orderly liquidation as of a date immediately prior to the announcement of the proposed Roll-Up transaction. The appraisal shall assume an orderly liquidation of Partnership assets over a 12-month period. The terms of the engagement of the independent expert shall clearly state that the engagement is for the benefit of the Partnership and the Investor Partners. A summary of the independent appraisal, indicating all material assumptions underlying the appraisal, shall be included in a report to the Investor Partners in connection with a proposed Roll-Up.

In connection with a proposed Roll-Up, Investor Partners who vote "no" on the proposal shall be offered the choice of:

accepting the securities of the Roll-Up Entity offered in the proposed Roll-Up; or

(a) remaining as Investor Partners in the Partnership and preserving their interests therein on the same terms and conditions as existed previously; or (b) receiving cash in an amount equal to the Investor Partners' pro-rata share of the appraised value of the net assets of the Partnership.

The Partnership shall not participate in any proposed Roll-Up which, if approved, would result in the diminishment of any Investor Partner's voting rights under the Roll-Up Entity's chartering agreement. In no event shall the democracy rights of Investor Partners in the Roll-Up Entity be less than those provided for under Sections 7.07 and 7.08 of this Agreement. If the Roll-Up Entity is a corporation, the democracy rights of Investor Partners shall correspond to the democracy rights provided for in this Agreement to the greatest extent possible.

The Partnership shall not participate in any proposed Roll-Up transaction which includes provisions which would operate to materially impede or frustrate the accumulation of shares by any purchaser of the securities of the Roll-Up Entity (except to the minimum extent necessary to preserve the tax status of the Roll-Up Entity); nor shall the Partnership participate in any proposed Roll-Up transaction which would limit the ability of an Investor Partner to exercise the voting rights of its securities of the Roll-Up Entity on the basis of the number of Partnership Units held by that Investor Partner.

The Partnership shall not participate in a Roll-Up in which Investor Partners' rights of access to the records of the Roll-Up Entity will be less than those provided for under Section 8.01 of this Agreement.

The Partnership shall not participate in any proposed Roll-Up transaction in which any of the costs of the transaction would be borne by the Partnership if the Roll-Up is not approved by the Investor Partners.

The Partnership shall not participate in a Roll-Up transaction unless the Roll-Up transaction is approved by at least 66 2/3% in interest of the Investor Partners.

Managing General Partner

bb. Managing General Partner. The Managing General Partner shall have the sole and exclusive right and power to manage and control the affairs of and to operate the Partnership and to do all things necessary to carry on the business of the Partnership for the purposes described in Section 1.03 hereof and to conduct the activities of the Partnership as set forth in Article V hereof. No financial institution or any other person, firm, or corporation dealing with the Managing General Partner shall be required to ascertain whether the Managing General Partner is acting in accordance with this Agreement, but such financial institution or such other person, firm, or corporation shall be protected in relying solely upon the deed, transfer, or assurance of and the execution of such instrument or instruments by the Managing General Partner. The Managing General Partner shall devote so much of its time to the business of the Partnership as in its judgment the conduct of the Partnership's business shall reasonably require and shall not be obligated to do or perform any act or thing in connection with the business of the Partnership not expressly set forth herein. The Managing General Partner may engage in business ventures of any nature and description independently or with others and neither the Partnership nor any of its Investor Partners shall have any rights in and to such independent ventures or the income or profits derived therefrom. However, except as otherwise provided herein, the Managing General Partner and any of its Affiliates may pursue business opportunities that are consistent with the Partnership's investment objectives for their own account only after they have determined that such opportunity either cannot be pursued by the Partnership because of insufficient funds or because it is not appropriate for the Partnership under the existing circumstances.

cc. Authority of Managing General Partner. The Managing General Partner is specifically authorized and empowered, on behalf of the Partnership, and by consent of the Investor Partners herein given, to do any act or execute any document or enter into any contract or any agreement of any nature necessary or desirable, in the opinion of the Managing General Partner, in pursuance of the purposes of the Partnership. Without limiting the generality of the foregoing, in addition to any and all other powers conferred upon the Managing General Partner pursuant to this Agreement and the Act, and except as otherwise prohibited by law or hereunder, the Managing General Partner shall have the power and authority to:

a. Acquire leases and other interests in oil and/or gas properties in furtherance of the Partnership's business;

b. Enter into and execute pooling agreements, farm out agreements, operating agreements, unitization agreements, dry and bottom hole and acreage contribution letters, construction contracts, and any and all documents or instruments customarily employed in the oil and gas industry in connection with the acquisition, sale, exploration, development, or operation of oil and gas properties, and all other instruments deemed by the Managing General Partner to be necessary or appropriate to the proper operation of oil or gas properties or to effectively and properly perform its duties or exercise its powers hereunder;

c. Make expenditures and incur any obligations it deems necessary to implement the purposes of the Partnership; employ and retain such personnel as it deems desirable for the conduct of the Partnership's activities, including employees, consultants, and attorneys; and exercise on behalf of the Partnership, in such manner as the Managing General Partner in its sole judgment deems best, of all rights, elections, and obligations granted to or imposed upon the Partnership;

d. Manage, operate, and develop any Partnership property, and enter into operating agreements with respect to properties acquired by the Partnership, including an operating agreement with the Managing General Partner as described in the Prospectus, which agreements may contain such terms, provisions, and conditions as are usual and customary within the industry and as the Managing General Partner shall approve;

e. Compromise, sue, or defend any and all claims in favor of or against the Partnership;

f. Subject to the provisions of Section 8.04 hereof, make or revoke any election permitted the Partnership by any taxing authority;

g. Perform any and all acts it deems necessary or appropriate for the protection and preservation of the Partnership assets;

h. Maintain at the expense of the Partnership such insurance coverage for public liability, fire and casualty, and any and all other insurance necessary or appropriate to the business of the Partnership in such amounts and of such types as it shall determine from time to time;

i. Buy, sell, or lease property or assets on behalf of the Partnership;

j. Enter into agreements to hire services of any kind or nature;

k. Assign interests in properties to the Partnership;

l. Enter into soliciting dealer agreements and perform all of the Partnership's obligations thereunder, to issue and sell Units pursuant to the terms and conditions of this Agreement, the Subscription Agreements, and the Prospectus, to accept and execute on behalf of the Partnership Subscription Agreements, and to admit original and substituted Partners; and

m. Perform any and all acts, and execute any and all documents it deems necessary or appropriate to carry out the purposes of the Partnership.

dd. Certain Restrictions on Managing General Partner's Power and Authority. Notwithstanding any other provisions of this Agreement to the contrary, neither the Managing General Partner nor any Affiliate of the Managing General Partner shall have the power or authority to, and shall not, do, perform, or authorize any of the following:

Use any revenues from Partnership operations for the purposes of acquiring Leases in new or unrelated Prospects or paying any Organization and Offering Expenses; provided, however, that revenues from Partnership operations may be used for other Partnership operations, including without limitation for the purposes of drilling, completing, maintaining, recompleting, and operating wells on existing Partnership Prospects and acquiring and developing new Leases to the extent such Leases are considered by the Managing General Partner in its sole discretion to be a part of a Prospect in which the Partnership then owns a Lease;

Without having first received the prior consent of the holders of a majority of the then outstanding Units entitled to vote,

1. sell all or substantially all of the assets of the Partnership (except upon liquidation of the Partnership pursuant to Article IX hereof), unless cash funds of the Partnership are insufficient to pay the obligations and other liabilities of the Partnership;

2. dispose of the good will of the Partnership;

3. do any other act which would make it impossible to carry on the ordinary business of the Partnership; or

4. agree to the termination or amendment of any operating agreement to which the Partnership is a party, or waive any rights of the Partnership thereunder, except for amendments to the operating agreement which the Managing General Partner believes are necessary or advisable to ensure that the operating agreement conforms to any changes in or modifications to the Code or that do not adversely affect the Investor Partners in any material respect;

Guarantee in the name or on behalf of the Partnership the payment of money or the performance of any contract or other obligation of any Person other than the Partnership;

Bind or obligate the Partnership with respect to any matter outside the scope of the Partnership business;

Use the Partnership name, credit, or property for other than Partnership purposes;

Take any action, or permit any other person to take any action, with respect to the assets or property of the Partnership which does not benefit the Partnership, including, among other things, utilization of funds of the Partnership as compensating balances for its own benefit or the commitment of future production;

Benefit from any arrangement for the marketing of oil and gas production or other relationships affecting the property of the Managing General Partner and the Partnership, unless such benefits are fairly and equitably apportioned among the Managing General Partner, its Affiliates, and the Partnership;

Utilize Partnership funds to invest in the securities of another person except in the following instances:

investments in working interests or undivided lease interests made in the ordinary course of the Partnership's business;

temporary investments made in compliance with Section 2.02(f) of this Agreement;

investments involving less than 5% of Partnership capital which are a necessary and incidental part of a property acquisition transaction; and

investments in entities established solely to limit the Partnership's liabilities associated with the ownership or operation of property or equipment, provided, in such instances duplicative fees and expenses shall be prohibited; or

Sell, transfer, or assign its interest (except for a collateral assignment which may be granted to a bank or other financial institution) in the Partnership, or any part thereof, or otherwise to withdraw as Managing General Partner of the Partnership without one hundred twenty (120) days prior written notice to and the written consent of Investor Partners owning a majority of the then outstanding Units.

ee. Indemnification of Managing General Partner. The Managing General Partner shall have no liability to the Partnership or to any Investor Partner for any loss suffered by the Partnership which arises out of any action or inaction of the Managing General Partner if the Managing General Partner, in good faith, determined that such course of conduct was in the best interest of the Partnership, that the Managing General Partner was acting on behalf of or performing services for the Partnership, and that such course of conduct did not constitute negligence or misconduct of the Managing General Partner. The Managing General Partner shall be indemnified by the Partnership against any losses, judgments, liabilities, expenses, and amounts paid in settlement of any claims sustained by it in connection with the Partnership, provided that the Managing General Partner has determined in good faith that the course of conduct which caused the loss or liability was in the best interests of the Partnership, that the Managing General Partner was acting on behalf of or performing services for the Partnership, and that the same were not the result of negligence or misconduct on the part of the Managing General Partner. Indemnification of the Managing General Partner is recoverable only from the tangible net assets of the Partnership, including the insurance proceeds from the Partnership's insurance policies and the insurance and indemnification of the Partnership's subcontractors, and is not recoverable from the Investor Partners.

Notwithstanding the above, the Managing General Partner and any person acting as a broker-dealer shall not be indemnified for liabilities arising under Federal and state securities laws unless (a) there has been a successful adjudication on the merits of each count involving securities law violations, (b) such claims have been dismissed with prejudice on the merits by a court of competent jurisdiction, or (c) a court of competent jurisdiction approves a settlement of such claims against a particular indemnitee and finds that indemnification of the settlement and the related costs should be made, and the court considering the request for indemnification has been advised of the position of the Securities and Exchange Commission and of any state securities regulatory authority in which securities of the Partnership were offered or sold as to indemnification for violations of securities laws; provided however, the court need only be advised of the positions of the securities regulatory authorities of those states (i) which are specifically set forth in the program agreement and (ii) in which plaintiffs claim they were offered or sold program units.

In any claim for indemnification for Federal or state securities laws violations, the party seeking indemnification shall place before the court the position of the Securities and Exchange Commission, the Massachusetts Securities Division, and the Tennessee Securities Division or respective state securities division, as the case may be, with respect to the issue of indemnification for securities law violations.

The advancement of Partnership funds to a sponsor or its affiliates for legal expenses and other costs incurred as a result of any legal action for which indemnification is being sought is permissible only if the Partnership has adequate funds available and the following conditions are satisfied:

the legal action relates to acts or omissions with respect to the performance of duties or services on behalf of the Partnership, and

the legal action is initiated by a third party who is not a participant, or the legal action is initiated by a participant and a court of competent jurisdiction specifically approves such advancement, and

the sponsor or its affiliates undertake to repay the advanced funds to the Partnership, together with the applicable legal rate of interest thereon, in cases in which such party is found not to be entitled to indemnification.

The Partnership shall not incur the cost of the portion of any insurance which insures the Managing General Partner against any liability as to which the Managing General Partner is herein prohibited from being indemnified.

ff. Withdrawal.

o Notwithstanding the limitations contained in Section 6.03(i) hereof, the Managing General Partner shall have the right, by giving written notice to the other Partners, to substitute in its stead as managing general partner any successor entity or any entity controlled by the Managing General Partner, provided that the successor Managing General Partner must have a tangible net worth of at least $5 million, and the Investor Partners, by execution of this Agreement, expressly consent to such a transfer, unless it would adversely affect the status of the Partnership as a partnership for federal income tax purposes.

a. The Managing General Partner may not voluntarily withdraw from the Partnership prior to the Partnership's completion of its primary drilling and/or acquisition activities, and then only after giving 120 days written notice. The Managing General Partner may not partially withdraw its property interests held by the Partnership unless such withdrawal is necessary to satisfy the bona fide request of its creditors or approved by a majority-in-interest vote of the Investor Partners. The Managing General Partner shall fully indemnify the Partnership against any additional expenses which may result from a partial withdrawal of property interests and such withdrawal may not result in a greater amount of direct costs or administrative costs being allocated to the Investor Partners. The withdrawing Managing General Partner shall pay all expenses incurred as a result of its withdrawal.

gg. Management Fee. The Partnership shall pay the Managing General Partner, on the date the Partnership is organized (as set forth in Section 1.01), a one-time management fee equal to 1½% of the total Subscriptions.

hh. Tax Matters and Financial Reporting Partner. The Managing General Partner shall serve as the Tax Matters Partner for purposes of Code Sections 6221 through 6233 and as the Financial Reporting Partner. The Partnership may engage its accountants and/or attorneys to assist the Tax Matters Partner in discharging its duties hereunder.

Investor Partners

ii. Management. No Investor Partner shall take part in the control or management of the business or transact any business for the Partnership, and no Investor Partner shall have the power to sign for or bind the Partnership. Any action or conduct of Investor Partners on behalf of the Partnership is hereby expressly prohibited. Any Investor Partner who violates this Section 7.01 shall be liable to the remaining Investor Partners, the Managing General Partner, and the Partnership for any damages, costs, or expenses any of them may incur as a result of such violation. The Investor Partners hereby grant to the Managing General Partner or its successors or assignees the exclusive authority to manage and control the Partnership business in its sole discretion and to thereby bind the

Partnership and all Partners in its conduct of the Partnership business. Investor Partners shall have the right to vote only with respect to those matters specifically provided for in these Articles. No Investor Partner shall have the authority to:

a. Assign the Partnership property in trust for creditors or on the assignee's promise to pay the debts of the Partnership;

b. Dispose of the goodwill of the business;

c. Do any other act which would make it impossible to carry on the ordinary business of the Partnership;

d. Confess a judgment;

e. Submit a Partnership claim or liability to arbitration or reference;

f. Make a contract or bind the Partnership to any agreement or document;

g. Use the Partnership's name, credit, or property for any purpose;

h. Do any act which is harmful to the Partnership's assets or business or by which the interests of the Partnership shall be imperiled or prejudiced; or

i. Perform any act in violation of any applicable law or regulations thereunder, or perform any act which is inconsistent with the terms of this Agreement.

jj. Indemnification of Additional General Partners. The Managing General Partner agrees to indemnify each of the Additional General Partners for the amounts of obligations, risks, losses, or judgments of the Partnership or the Managing General Partner which exceed the amount of applicable insurance coverage and amounts which would become available from the sale of all Partnership assets. Such indemnification applies to casualty losses and to business losses, such as losses incurred in connection with the drilling of an unproductive well, to the extent such losses exceed the Additional General Partners' interest in the undistributed net assets of the Partnership. If, on the other hand, such excess obligations are the result of the negligence or misconduct of an Additional General Partner, or the contravention of the terms of the Partnership Agreement by the Additional General Partner, then the foregoing indemnification by the Managing General Partner shall be unenforceable as to such Additional General Partner and such Additional General Partner shall be liable to all other Partners for damages and obligations resulting therefrom.

kk. Assignment of Units.

a. An Investor Partner may transfer all or any portion of his Units and the transferee shall become a Substituted Investor Partner (subject to all duties and obligations of an Investor Partner, including those contained in Section 4.04 herein, except to the extent excepted in the Act) subject to the following conditions (any transfer of such Units satisfying such conditions being referred to herein as a "Permitted Transfer"):

1. Except in the case of a transfer of Units at death or involuntarily by operation of law, the transferor and transferee shall execute and deliver to the Partnership such documents and instruments of conveyance as may be necessary or appropriate in the opinion of counsel to the Partnership to effect such transfer and to confirm the agreement of the transferee to be bound by the provisions of this Article VII. In any case not described in the preceding sentence, the transfer shall be confirmed by presentation to the Partnership of legal evidence of such transfer, in form and substance satisfactory to counsel to the Partnership. In all cases, the Partnership shall be

reimbursed by the transferor and/or transferee for all costs and expenses that it reasonably incurs in connection with such transfer;

2. The transferor and transferee shall furnish the Partnership with the transferee's taxpayer identification number and sufficient information to determine the transferee's initial tax basis in the Units transferred;

(iii) The Transferee shall have satisfied the suitability standards that have been established for an investment in the Partnership; and

(iv) The written consent of the Managing General Partner to such transfer shall have been obtained.

b. A Person who acquires one or more Units but who is not admitted as a Substituted Investor Partner pursuant to Section 7.03(c) hereof shall be entitled only to allocations and distributions with respect to such Units in accordance with this Agreement, but shall have no right to any information or accounting of the affairs of the Partnership, shall not be entitled to inspect the books or records of the Partnership, and shall not have any of the rights of an Additional General Partner or a Limited Partner under the Act or the Agreement.

c. Subject to the other provisions of this Article VII, a transferee of Units may be admitted to the Partnership as a Substituted Investor Partner only upon satisfaction of the conditions set forth below in this Section 7.03(c):

1. The Managing General Partner consents to such admission;

2. The Units with respect to which the transferee is being admitted were acquired by means of a Permitted Transfer;

3. The transferee becomes a party to this Agreement as a Partner and executes such documents and instruments as the Managing General Partner may reasonably request (including, without limitation, amendments to the Certificate of Limited Partnership) as may be necessary or appropriate to confirm such transferee as a Partner in the Partnership and such transferee's agreement to be bound by the terms and conditions hereof;

4. The transferee pays or reimburses the Partnership for all reasonable legal, filing, and publication costs that the Partnership incurs in connection with the admission of the transferee as a Partner with respect to the transferred Units; and

5. If the transferee is not an individual of legal majority, the transferee provides the Partnership with evidence satisfactory to counsel for the Partnership of the authority of the transferee to become a Partner and to be bound by the terms and conditions of this Agreement.

6. In any calendar quarter in which a Substituted Investor Partner is admitted to the Partnership, the Managing General Partner shall amend the certificate of limited partnership to effect the substitution of such Substituted Investor Partners, although the Managing General Partner may do so more frequently. In the case of assignments, where the assignee does not become a Substituted Investor Partner, the Partnership shall recognize the assignment not later than the last day of the calendar month following receipt of notice of assignment and required documentation.

d. Each Investor Partner hereby covenants and agrees with the Partnership for the benefit of the Partnership and all Partners that (i) he is not currently making a market in Units and (ii) he will not transfer any Unit on an established securities market or a secondary market (or the substantial equivalent thereof) within the meaning of Code Section 7704(b) (and any regulations, proposed regulations, revenue rulings, or other official pronouncements of the Service or Treasury Department that may be promulgated or published thereunder). Each Investor Partner further agrees that he will not transfer any Unit to any Person unless such Person agrees to be bound by this Section 7.03 and to transfer such Units only to Persons who agree to be similarly bound.

e. Restrictions on assignment of Units or the substitution of Investor Partners shall be allowed only to the extent necessary to preserve the tax status of the Partnership or the classification of Partnership income for tax purposes and any restriction shall be supported by an opinion of the Partnership's counsel as to its legal necessity.

ll. Prohibited Transfers.Any purported Transfer of Units that is not a Permitted Transfer shall be null and void and of no effect whatever; provided, that, if the Partnership is required to recognize a transfer that is not a Permitted Transfer (or if the Managing General Partner, in its sole discretion, elects to recognize a transfer that is not a Permitted Transfer), the interest transferred shall be strictly limited to the transferor's rights to allocations and distributions as provided by this Agreement with respect to the transferred Units, which allocations and distributions may be applied (without limiting any other legal or equitable rights of the Partnership) to satisfy the debts, obligations, or liabilities for damages that the transferor or transferee of such Units may have to the Partnership.

b. In the case of a transfer or attempted transfer of Units that is not a Permitted Transfer, the parties engaging or attempting to engage in such transfer shall be liable to indemnify and hold harmless the Partnership and the other Partners from all cost, liability, and damage that any of such indemnified Persons may incur (including, without limitation, incremental tax liability and lawyers' fees and expenses) as a result of such transfer or attempted transfer and efforts to enforce the indemnity granted hereby.

mm. Withdrawal by Investor Partners. Neither a Limited Partner nor an Additional General Partner may withdraw from the Partnership, except as otherwise provided in this Agreement.

nn. Removal of Managing General Partner.

a. The Managing General Partner may be removed at any time with the consent of Investor Partners owning a majority of the then outstanding Units, and upon the selection of a successor managing general partner or partners by Investor Partners owning a majority of the then outstanding Units.

b. Any successor Managing General Partner may be removed upon the terms and conditions provided in this Section.

c. In the event a managing general partner is removed, its respective interest in the assets of the Partnership shall be determined by independent appraisal by a qualified independent petroleum engineering consultant who shall be selected by mutual agreement of the Managing General Partner and the incoming sponsor. Such appraisal will take into account an appropriate discount to reflect the risk of recovery of oil and gas reserves, and, at its election, the removed managing general partner's interest in the Partnership assets may be distributed to it or the interest of the managing general partner in the Partnership may be retained by it as a Limited Partner in the successor limited partnership; provided, however, that if immediate payment to the removed managing general partner would impose financial or operational hardship upon the Partnership, as determined by the successor managing general partner in the exercise of its fiduciary duties to the Partnership, payment (plus reasonable interest) to the removed managing general partner may be postponed to that time when, in the determination of the successor managing general partner, payment will not cause a hardship to the Partnership. The cost of such appraisal shall be borne by the Partnership. The successor managing general partner shall have the option to purchase at least 20% of the removed managing general partner's interest for the value determined by the independent appraisal.

The removed managing general partner, at the time of its removal shall cause, to the extent it is legally possible, its successor to be transferred or assigned all its rights, obligations, and interests in contracts entered into by it on behalf of the Partnership. In any event, the removed managing general partner shall cause its rights, obligations, and interests in any such contract to terminate at the time of its removal.

d. Upon effectiveness of the removal of the managing general partner, the assets, books, and records of the Partnership shall be surrendered to the successor managing general partner, provided that the successor managing general partner shall have first (i) agreed to accept the responsibilities of the managing general partner, and (ii) made arrangements satisfactory to the original managing general partner to remove such managing general partner from personal liability on any Partnership borrowings or, if any Partnership creditor will not consent to such removal, agreed to indemnify the original managing general partner for any subsequent liabilities in respect to such borrowings. Immediately after the removal of the managing general partner, the successor managing general partner shall prepare, execute, file for recordation, and cause to be published, such notices or certificates as may be required by the Act.

oo. Calling of Meetings. Investor Partners owning 10% or more of the then outstanding Units entitled to vote shall have the right to request that the Managing General Partner call a meeting of the Partners. The Managing General Partner shall call such a meeting and shall deposit in the United States mails within fifteen days after receipt of such request, written notice to all Investor Partners of the meeting and the purpose of the meeting, which shall be held on a date not less than thirty nor more than sixty days after the date of mailing of such notice, at a reasonable time and place. Investor Partners shall have the right to submit proposals to the Managing General Partner for inclusion in the voting materials for the next meeting of Investor Partners for consideration and approval by the Investor Partners. Investor Partners shall have the right to vote in person or by proxy.

pp. Additional Voting Rights. Investor Partners shall be entitled to all voting rights granted to them by and under this Agreement and as specified by the Act. Each Unit is entitled to one vote on all matters; each fractional Unit is entitled to that fraction of one vote equal to the fractional interest in the Unit. Except as otherwise provided herein or in the Prospectus, at any meeting of Investor Partners, a vote of a majority in interest of Units represented at such meeting, in person or by proxy, with respect to matters considered at the meeting at which a quorum is present shall be required for approval of any such matters. In addition, except as otherwise provided in this Section and in Section 5.07(m), holders of a majority in interest of the then outstanding Units may, without the concurrence of the Managing General Partner, vote to (a) approve or disapprove the sale of all or substantially all of the assets of the Partnership, (b) dissolve the Partnership, (c) remove the Managing General Partner and elect a new managing general partner, (d) amend the Agreement; but any such amendment may not increase the duties or liabilities of any Investor Partner or the Managing General Partner or increase or decrease the profit or loss sharing or required capital contribution of any Investor Partner or the Managing General Partner without the approval of such Investor Partner or Managing General Partner; and any such amendment may not affect the classification of the Partnership's income or loss for federal income tax purposes without the unanimous approval of all Investor Partners, (e) elect a new managing general partner if the managing general partner elects to withdraw from the Partnership, and (f) cancel any contract for services with the Managing General Partner or any Affiliates without penalty upon sixty days' notice. The Partnership shall not participate in a Roll-Up unless the Roll-Up is approved by at least 66 2/3% in interest of the Investor Partners. A majority in interest of the then outstanding Units entitled to vote shall constitute a quorum. In determining the requisite percentage in interest of Units necessary to approve a matter on which the Managing General Partner and its Affiliates may not vote or consent, any Units owned by the Managing General Partner and its Affiliates shall not be included. With respect to the merger or consolidation of the Partnership or the sale of all or substantially all of the assets of the Partnership, Investor Partners shall have the right to exercise dissenter's rights in accordance with Section 31D-13-1301 et seq. of the West Virginia Business Corporation Act.

qq. Voting by Proxy. The Investor Partners may vote either in person or by proxy.

rr. Conversion of Additional General Partner Interests into Limited Partner Interests.

The Managing General Partner shall convert the interests of all Additional General Partners in a particular Partnership to interests of Limited Partners in that Partnership upon completion of drilling of that Partnership.

The Managing General Partner shall notify all Additional General Partners at least 30 days prior to any material change in the amount of the Partnership's insurance coverage. Within this 30-day period, and notwithstanding Section 7.10(a), Additional General Partners shall have the right to immediately convert their Units into Units of limited partnership interest by giving written notice to the Managing General Partner.

As provided herein, Additional General Partners may elect to convert, transfer, and exchange their interests for Limited Partner interests in the Partnership upon receipt by the Managing General Partner of written notice of such election. An Additional General Partner may request conversion of his interests for Limited Partner interests at any time after one year following the closing of the securities offering which relates to the Agreement and the disbursement to the Partnership of the proceeds of such securities offering.

a. The Managing General Partner shall cause the conversion to be effected as promptly as possible as prudent business judgment dictates. Conversion of an Additional General Partnership interest to a Limited Partnership interest in a particular Partnership shall be conditioned upon a finding by the Managing General Partner that such conversion will not cause a termination of the Partnership for federal income tax purposes, and will be effective upon the Managing General Partner's filing an amendment to its Certificate of Limited Partnership. The Managing General Partner is obligated to file an amendment to its Certificate at any time during the full calendar month after receipt of the required notice of the Additional General Partner and a determination of the Managing General Partner that the conversion will not constitute a termination of the Partnership for tax purposes. Effecting conversion is subject to the satisfaction of the condition that the electing Additional General Partner provide written notice to the Managing General Partner of such intent to convert. Upon such transfer and exchange, such Additional General Partners shall be Limited Partners; however, they will remain liable to the Partnership for any additional Capital Contribution(s) required for their proportionate share of any Partnership obligation or liability arising prior to the conversion.

b. Limited Partners may not convert and/or exchange their interests for Additional General Partner interests.

ss. Unit Repurchase Program.

i. Beginning with the third anniversary after the date of the first cash distribution of the Partnership, Investor Partners may request the Managing General Partner to repurchase their Units, subject to the Managing General Partner's available borrowing capacity under its loan agreements to repurchase. If the Managing General Partner receives requests for repurchase of Units and subject to such borrowing capacity, the Managing General Partner shall annually repurchase for cash up to 10% of the Units originally subscribed to in the Partnership.

ii. The Unit Repurchase Program shall be subject to the following conditions:

The Managing General Partner must receive written notification from the particular Investor Partner of such Partner's intention to exercise the repurchase right; and

The Managing General Partner shall provide the Investor Partner a written notice of a specified price for purchase of the particular Units within 30 days of the Managing General Partner's receipt of written notification; and

The Managing General Partner's offer shall remain open for 60 days after the Managing General Partner's mailing of the price notice to the Investor Partner.

iii. The Managing General Partner shall not favor one particular Partnership of which it is a Managing General Partner over another in the repurchase of Units. Each Partnership shall stand on equal footing before the Managing General Partner. To the extent that the Managing General Partner is unable, due to limitations imposed by the Code or insufficient borrowing capacity under the Managing General Partner's loan agreement(s) with banks, to repurchase all Units requested for repurchase, each Investor Partner requesting repurchase shall be entitled to have his Units repurchased on a "first come-first served" basis, regardless of Partnership, provided that the Managing General Partner determines that the repurchase of a particular Investor Partner's Units will not result in the termination of the Partnership for federal income tax purposes and in the Partnership's being treated as a "publicly traded partnership." If Investor Partners request the repurchase of more than 10% of the Units of a particular Partnership during that Partnership's taxable year, Units shall be purchased on a "first come-first served" basis with respect to that Partnership. To the extent that the Managing General Partner is unable to repurchase all Units requested for repurchase at the same time by Partners of any Partnership, the Managing General Partner shall repurchase those particular Units on a pro-rata basis.

iv. The offer price which the Managing General Partner shall make shall be a cash amount equal to four times cash distributions attributable to the subject Unit from production for the 12 months prior to the month in which the above-referenced written notification is actually received by the Managing General Partner at its corporate offices. The Managing General Partner may, in its sole and absolute discretion, increase the repurchase price for Units requested for repurchase.

v. Upon any repurchase, the Managing General Partner shall hold such purchased Units for its own use and not for resale and it shall not create a market in the Units.

tt. Liability of Partners. Except as otherwise provided in this Agreement or as otherwise provided by the Act, each General Partner shall be jointly and severally liable for the debts and obligations of the Partnership. In addition, each Additional General Partner shall be jointly and severally liable for any wrongful acts or omissions of the Managing General Partner and/or the misapplication of money or property of a third party by the Managing General Partner acting within the scope of its apparent authority to the extent such acts or omissions are chargeable to the Partnership.

Books and Records

uu. Books and Records.

a. For accounting and income tax purposes, the Partnership shall operate on a calendar year.

b. The Managing General Partner shall keep just and true records and books of account with respect to the operations of the Partnership and shall maintain and preserve during the term of the Partnership and for four years thereafter all such records, books of account, and other relevant Partnership documents. The Managing General Partner shall maintain for at least six years all records necessary to substantiate the fact that Units were sold only to purchasers for whom such Units were suitable. Such books shall be maintained at the principal place of business of the Partnership and shall be kept on the accrual method of accounting.

c. The Managing General Partner shall keep or cause to be kept complete and accurate books and records with respect to the Partnership's business, which books and records shall at all times be kept at the principal office of the Partnership. Any records maintained by the Partnership in the regular course of its business, including the names and addresses of Investor Partners, books of account, and records of Partnership proceedings, may be kept on or be in the form of RAM disks, magnetic tape, photographs, micrographics, or any other information storage device, provided that the records so kept are convertible into clearly legible written form within a reasonable period of time. The books and records of the Partnership shall be made available for review and copying by any Investor Partner or his representative at any reasonable time.

d. • An alphabetical list of the names, addresses and business telephone numbers of the Investor Partners of the Partnership along with the number of Units held by each of them (the "participant list") shall be maintained as a part of the books and records of the Partnership and shall be available for the inspection by any Investor Partner or its designated agent at the home office of the Partnership upon the request of the Investor Partner;

1. The participant list shall be updated at least quarterly to reflect changes in the information contained therein;

2. A copy of the participant list shall be mailed to any Investor Partner requesting the participant list within ten days of the request. The copy of the participant list shall be printed in alphabetical order, on white paper, and in a readily readable type size (in no event smaller than 10-point type). A reasonable charge for copy work may be charged by the Partnership.

3. The purposes for which an Investor Partner may request a copy of the participant list include, without limitation, matters relating to voting rights under the Partnership Agreement and the exercise of Investor Partners' rights under federal proxy laws; and

4. If the Managing General Partner of the Partnership neglects or refuses to exhibit, produce, or mail a copy of the participant list as requested, the Managing General Partner shall be liable to any Investor Partner requesting the list for the costs, including attorneys' fees, incurred by that Investor Partner for compelling the production of the participant list, and for actual damages suffered by any Investor Partner by reason of such refusal or neglect. It shall be a defense that the actual purpose and reason for the requests for inspection or for a copy of the participant list is to secure the list of Investor Partners or other information for the purpose of selling such list or information or copies thereof, or of using the same for a commercial purpose other than in the interest of the applicant as an Investor Partner relative to the affairs of the Partnership. The Managing General Partner may require the Investor Partner requesting the participant list to represent that the list is not requested for a commercial purpose unrelated to the Investor Partner's interest in the Partnership. The remedies provided hereunder to Investor Partners requesting copies of the participant list are in addition to, and shall not in any way limit, other remedies available to Investor Partners under federal law, or the laws of any state.

vv. Reports. The Managing General Partner shall deliver to each Investor Partner the following financial statements and reports at the times indicated below:

a. Within 75 days after the end of the first six months of each fiscal year (for such six month period) and within 120 days after the end of each fiscal year (for such year), financial statements, including a balance sheet and statements of income, Partners' equity, and cash flows, all of which shall be prepared in accordance with generally accepted accounting principles. The annual financial statements shall be accompanied by (i) a report of an independent certified public accountant designated by the Managing General Partner stating that an audit of such financial statements has been made in accordance with generally accepted auditing standards and that in its opinion such financial statements present fairly the financial condition, results of operations, and cash flow of the Partnership in accordance with generally accepted accounting principles and (ii) a reconciliation of such financial statements with the information furnished to the Investor Partners for federal income tax reporting purposes.

b. Annually by March 15 of each year, a report containing such information as may be deemed to enable each Investor Partner to prepare and file his federal income tax return and any required state income tax return.

c. Annually within 120 days after the end of each fiscal year, (i) a summary of the computations of the total estimated proved oil and gas reserves of the Partnership as of the end of such fiscal year and the dollar value thereof at then existing prices and a computation of each Investor Partner's interest in such value, such reserve computations to be based upon engineering reports prepared by qualified independent petroleum engineers, (ii) an estimate of the time required for the extraction of such proved reserves and the present worth thereof (discounted at a rate generally accepted in the oil and gas industry and undiscounted), and (iii) a statement that because of the time period required to extract such reserves the present value of revenues to be obtained in the future is less than if such revenues were immediately receivable. Each such reported shall be prepared in accordance with customary and generally accepted standards and practices for petroleum engineers and shall be prepared by a recognized independent petroleum engineer selected from time to time by the Managing General Partner. No later than 90 days following the occurrence of an event resulting in a reduction in an amount of 10% or more of the estimated value of the proved oil and gas reserves as last reported to the Investor Partners, other than a reduction resulting from normal production, sales of reserves, or product price changes, a new summary conforming to the requirements set forth above in this Section 8.02(c) shall be delivered to the Investor Partners.

d. Within 75 days after the end of the first six months of each fiscal year and within 120 days after the end of each fiscal year, (i) a summary itemization, by type and/or classification, of any transaction of the Partnership since the date of the last such report with the Managing General Partner or any Affiliate thereof and the total fees, compensation, and reimbursement paid by the Partnership (or indirectly on behalf of the Partnership) to the Managing General Partner and its Affiliates, and (ii) a schedule reflecting (A) the total costs of the Partnership (and, where applicable, the costs pertaining to each Lease) and the costs paid by the Managing General Partner and by the Investor Partners and (B) the total revenues of the Partnership and the revenues received by or credited to the accounts of the Managing General Partner and the Investing Partners. Each semi-annual report delivered by the Managing General Partner may contain summary estimates of the information described in subdivision (i) of Section 8.02(c).

e. Monthly within 15 days after the end of each calendar month while the Partnership is participating in the drilling and completion of wells in which it has an interest until the end of such activity, and thereafter for a period of three years within 75 days after the end of the first six months of each fiscal year and within 120 days after the end of each fiscal year, (i) a description of each Prospect or field in which the Partnership owns Leases including the cost, location, number of acres under lease, and the interest owned therein by the program (provided that after the initial description of each such Prospect or field has been provided to the Investor Partners only material changes, if any, with respect to such Prospect or field need be described), (ii) a description of all farmins, farmouts and joint ventures of the Partnership made since the date of the last such report, including the reason therefor, the location and timing thereof, the person to whom made and the terms thereof, and (iii) a summary of the wells drilled by the Partnership, indicating whether each of such wells has been completed, a statement of the cost of each well completed or abandoned and the reason for abandoning any well after commencement of production. Each report delivered by the Managing General Partner may contain summary estimates of the information described in subsection (iii).

f. The Managing General Partner shall cause the Partnership's independent auditors to audit the financial statements of the Partnership in accordance with generally accepted auditing standards. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, which would include an assessment as to whether or not the method used to make the allocations of costs was consistent with the method described in the Prospectus. If the Managing General Partner subsequently decides to allocate expenses in a manner different from the manner described in the Prospectus, such change shall be reported by the Managing General Partner to the Investor Partners together with an explanation of why such change was made and the basis for determining the reasonableness of the new allocation method.

g. Such other reports and financial statements as the Managing General Partner shall determine from time to time.

h. Concurrently with their transmittal to Investor Partners and as required, the Managing General Partner shall file a copy of each such report with the California Commissioner of Corporations and with the securities divisions of other states.

ww. Bank Accounts. All funds of the Partnership shall be deposited in such separate bank account or accounts, short term obligations of the U.S. Government or its agencies, or other interest-bearing investments and money market or liquid asset mutual funds as shall be determined by the Managing General Partner. All withdrawals therefrom shall be made upon checks signed by the Managing General Partner or any person authorized to do so by the Managing General Partner.

xx. Federal Income Tax Elections.

a. Except as otherwise provided in this Section 8.04, all elections required or permitted to be made by the Partnership under the Code shall be made by the Managing General Partner in its sole discretion. Each Partner agrees to provide the Partnership with all information necessary to give effect to any election to be made by the Partnership.

b. The Partnership shall elect to currently deduct IDC as an expense for income tax purposes and shall require any partnership, joint venture, or other arrangement in which it is a party to make such an election.

Dissolution; Winding-up

yy. Dissolution.

a. Except as otherwise provided herein, the retirement, withdrawal, removal, death, insanity, incapacity, dissolution, or bankruptcy of any Investor Partner shall not dissolve the Partnership. The successor to the rights of such Investor Partner shall have all the rights of an Investor Partner for the purpose of settling or administering the estate or affairs of such Investor Partner; provided, however, that no successor shall become a substituted Investor Partner except in accordance with Article VII hereof; provided, further, that upon the withdrawal of an Additional General Partner, the Partnership shall be dissolved and wound up unless at that time there is at least one other General Partner, in which event the business of the Partnership shall continue to be carried on. Neither the expulsion of any Investor Partner nor the admission or substitution of an Investor Partner shall work a dissolution of the Partnership. The estate of a deceased, insane, incompetent, or bankrupt Investor Partner shall be liable for all his liabilities as an Investor Partner.

b. The Partnership shall be dissolved upon the earliest to occur of: (i) the written consent of the Investor Partners owning a majority in interest of the then-outstanding Units to dissolve and wind up the affairs of the Partnership; (ii) subject to the provisions of Subsection (c) below, the retirement, withdrawal, removal, death, adjudication of insanity or incapacity, or bankruptcy (or, in the case of a corporate managing general partner, the withdrawal, removal, filing of a certificate of dissolution, liquidation, or bankruptcy) of the Managing General Partner; (iii) the sale, forfeiture, or abandonment of all or substantially all of the Partnership's property; (iv) December 31, 2055; (v) a dissolution event described in Subsection (a) above; or (vi) any event causing dissolution of the Partnership under the Act.

c. In the case of any event described in Subsection (b)(ii) above, if a successor Managing General Partner is selected by Partners owning a majority in interest of the then outstanding Units within ninety (90) days after such Section 9.01(b)(ii) event, and if such Investor Partners agree, within such 90 day period to continue the business of the Partnership, or if the remaining managing general partner, if any, continues the business of the Partnership, then the Partnership shall not be dissolved.

d. If the retirement, withdrawal, removal, death, insanity, incapacity, dissolution, liquidation, or bankruptcy of any Partner, or the assignment of a Partner's interest in the Partnership, or the substitution or admission of a new Partner, shall be deemed under the Act to cause a dissolution of the Partnership, then, except as provided in Section 9.01(c), the remaining Partners may, in accordance with the Act, continue the Partnership business as a new partnership and all such remaining Partners agree to be bound by the provisions of this Agreement.

zz. Liquidation. Upon a dissolution and final termination of the Partnership, the Managing General Partner, or in the event there is no Managing General Partner, any other person or entity selected by the Investor Partners (hereinafter referred to as a "Liquidator") shall cause the affairs of the Partnership to be wound up and shall take account of the Partnership's assets (including contributions, if any, of the Managing General Partner pursuant to Section 3.01(e) herein) and liabilities, and the assets shall, subject to the provisions of Section 9.03(b) herein, be liquidated as promptly as is consistent with obtaining the fair market value thereof, and the proceeds therefrom (which dissolution and liquidation may be accomplished over a period spanning one or more tax years in the sole discretion of the Managing General Partner or Liquidator), to the extent sufficient therefor, shall be applied and distributed in accordance with Section 9.03.

aaa. Winding-up.

a. Upon the dissolution of the Partnership and winding up of its affairs, the assets of the Partnership shall be distributed as follows:

1. all of the Partnership's debts and liabilities to persons other than the Managing General Partner shall be paid and discharged;

2. all outstanding debts and liabilities to the Managing General Partner shall be paid and discharged;

3. assets shall be distributed to the Partners to the extent of their positive Capital Account balances, pro rata, in accordance with such positive Capital Account balances; and

4. any assets remaining after the Partners' Capital Accounts have been reduced to zero pursuant to Section 9.03(c) herein shall be distributed 75% to the Investor Partners and 25% to the Managing General Partner, except as otherwise revised pursuant to Section 2.01(a) and/or Section 4.02.

b. Distributions pursuant to this Section 9.03 shall be made in cash or in kind to the Partners, at the election of the Partners. Notwithstanding the provision of this Section 9.03(b), in no event shall the Partners reserve the right to take in kind and separately dispose of their share of production.

c. Any in kind property distributions to the Investor Partners shall be made to a liquidating trust or similar entity for the benefit of the Investor Partners, unless at the time of the distribution:

the Managing General Partner shall offer the individual Investor Partners the election of receiving in kind property distributions and the Investor Partners accept such offer after being advised of the risks associated with such direct ownership; or

there are alternative arrangements in place which assure the Investor Partners that they will not, at any time, be responsible for the operation or disposition of Partnership properties.

The winding up of the affairs of the Partnership and the distribution of its assets shall be conducted exclusively by the Managing General Partner or the Liquidator, who is hereby authorized to do any and all acts and things authorized by law for these purposes.

Power of Attorney

bbb. Managing General Partner as Attorney-in-Fact. The undersigned makes, constitutes, and appoints the Managing General Partner the true and lawful attorney for the undersigned, and in the name, place, and stead of the undersigned from time to time to make, execute, sign, acknowledge, and file:

a. Any notices or certificates as may be required under the Act and under the laws of any other state or jurisdiction in which the Partnership shall engage, or seek to engage, to do business and to do such other acts as are required to constitute the Partnership as a limited partnership under such laws.

b. Any amendment to the Agreement pursuant to and which complies with Section 11.09 herein.

c. Such certificates, instruments, and documents as may be required by, or may be appropriate under the laws of any state or other jurisdiction in which the Partnership is doing or intends to do business and with the use of the name of the Partnership by the Partnership.

d. Such certificates, instruments, and documents as may be required by, or as may be appropriate for the undersigned to comply with, the laws of any state or other jurisdiction to reflect a change of name or address of the undersigned.

e. Such certificates, instruments, and documents as may be required to be filed with the Department of Interior (including any bureau, office or other unit thereof, whether in Washington, D.C. or in the field, or any officer or employee thereof), as well as with any other federal or state agencies, departments, bureaus, offices, or authorities and pertaining to (i) any and all offers to lease, leases (including amendments, modifications, supplements, renewals, and exchanges thereof) of, or with respect to, any lands under the jurisdiction of the United States or any state including without limitation lands within the public domain, and acquired lands, and provides for the leasing thereof; (ii) all statements of interest and holdings on behalf of the Partnership or the undersigned; (iii) any other statements, notices, or communications required or permitted to be filed or which may hereafter be required or permitted to be filed under any law, rule, or regulation of the United States, or any state relating to the leasing of lands for oil or gas exploration or development; (iv) any request for approval of assignments or transfers of oil and gas leases, any unitization or pooling agreements and any other documents relating to lands under the jurisdiction of the United States or any state; and (v) any other documents or instruments which said attorney-in-fact in its sole discretion shall determine should be filed.

f. Any further document, including furnishing verified copies of the Agreement and/or excerpts therefrom, which said attorney-in-fact shall consider necessary or convenient in connection with any of the foregoing, hereby giving said attorney-in-fact full power and authority to do and perform each and every act and thing whatsoever requisite and necessary to be done in and about the foregoing as fully as the undersigned might and could do if personally present, and hereby ratifying and confirming all that said attorney-in-fact shall lawfully do to cause to be done by virtue hereof.

ccc. Nature of Special Power. The foregoing grant of authority:

a. is a special Power of Attorney coupled with an interest, is irrevocable, and shall survive the death of the undersigned;

b. shall survive the delivery of any assignment by the undersigned of the whole or any portion of his Units; except that where the assignee thereof has been approved by the Managing General Partner for admission to the Partnership as a substitute general or limited Partner as the case may be, the Power of Attorney shall survive the delivery of such assignment for the sole purpose of enabling said attorney-in-fact to execute, acknowledge, and file any instrument necessary to effect such substitution; and

c. may be exercised by said attorney-in-fact with full power of substitution and resubstitution and may be exercised by a listing of all of the Partners executing any instrument with a single signature of said attorney-in-fact.

Miscellaneous Provisions

ddd. Liability of Parties. By entering into this Agreement, no party shall become liable for any other party's obligations relating to any activities beyond the scope of this Agreement, except as provided by the Act. If any party suffers, or is held liable for, any loss or liability of the Partnership which is in excess of that agreed upon herein, such party shall be indemnified by the other parties, to the extent of their respective interests in the Partnership, as provided herein.

eee. Notices. Any notice, payment, demand, or communication required or permitted to be given by any provision of this Agreement shall be deemed to have been sufficiently given or served for all purposes if delivered personally to the party or to an officer of the party to whom the same is directed or sent by registered or certified mail, postage and charges prepaid, addressed as follows (or to such other address as the party shall have furnished in writing in accordance with the provisions of this Section):

If to the Managing General Partner, 103 East Main Street, Bridgeport, West Virginia 26330;

If to an Investor Partner, at such Investor Partner's address for purposes of notice which is set forth on Exhibit A attached hereto.

Unless otherwise expressly set forth in this Agreement to the contrary, any such notice shall be deemed to be given on the date on which the same was deposited in a regularly maintained receptacle for the deposit of United States mail, addressed and sent as aforesaid.

fff. Paragraph Headings. The headings in this Agreement are inserted for convenience and identification only and are in no way intended to describe, interpret, define, or limit the scope, extent, or intent of this Agreement or any provision hereof.

ggg. Severability. Every portion of this Agreement is intended to be severable. If any term or provision hereof is illegal or invalid by any reason whatsoever, such illegality or invalidity shall not affect the validity of the remainder of this Agreement.

hhh. Sole Agreement. This Agreement constitutes the entire understanding of the parties hereto with respect to the subject matter hereof and no amendment, modification, or alteration of the terms hereof shall be binding unless the same be in writing, dated subsequent to the date hereof and duly approved and executed by the Managing General Partner and such percentage of Investor Partners as provided in Section 11.09 of this Agreement.

iii. Applicable Law. This Agreement, which shall be governed exclusively by its terms, is intended to comply with the Code and with the Act and shall be interpreted consistently therewith.

jjj. Execution in Counterparts. This Agreement may be executed in any number of counterparts with the same effect as if all parties hereto had all signed the same document. All counterparts shall be construed together and shall constitute one agreement.

kkk. Waiver of Action for Partition. Each of the parties irrevocably waives, during the term of the Partnership, any right that it may have to maintain any action for partition with respect to the Partnership and the property of the Partnership.

lll. Amendments.

a. Unless otherwise specifically herein provided, this Agreement shall not be amended without the consent of the Investor Partners owning a majority of the then outstanding Units entitled to vote.

b. The Managing General Partner may, without notice to, or consent of, any Investor Partner, amend any provisions of these Articles, or consent to and execute any amendment to these Articles, to reflect:

1. A change in the name or location of the principal place of business of the Partnership;

2. The admission of substituted or additional Investor Partners in accordance with these Articles;

3. A reduction in, return of, or withdrawal of, all or a portion of any Investor Partner's Capital Contribution;

4. A correction of any typographical error or omission;

5. A change which is necessary in order to qualify the Partnership as a limited partnership under the laws of any other state or which is necessary or advisable, in the opinion of the Managing General Partner, to ensure that the Partnership will be treated as a partnership and not as an association taxable as a corporation for federal income tax purposes;

6. A change in the allocation provisions, in accordance with the provisions of Section 3.02(l) herein, in a manner that, in the sole opinion of the Managing General Partner (which opinion shall be determinative), would result in the most favorable aggregate consequences to the Investor Partners as nearly as possible consistent with the allocations contained herein, for such allocations to be recognized for federal income tax purposes due to developments in the federal income tax laws or otherwise; or

7. Any other amendment similar to the foregoing;

provided, however, that the Managing General Partner shall have no authority, right, or power under this Section to amend the voting rights of the Investor Partners.

mmm. Consent to Allocations and Distributions. The methods herein set forth by which allocations and distributions are made and apportioned are hereby expressly consented to by each Partner as an express condition to becoming a Partner.

nnn. Ratification. The Investor Partner whose signature appears at the end of this Article hereby specifically adopts and approves every provision of this Agreement to which the signature page is attached.

ooo. Substitution of Signature Pages. This Agreement has been executed in duplicate by the undersigned Investor Partners and one executed copy of the signature page is attached to the undersigned's copy of this Agreement. It is agreed that the other executed copy of such signature page may be attached to an identical copy of this Agreement together with the signature pages from counterpart Agreements which may be executed by other Investor Partners.

ppp. Incorporation by Reference. Every exhibit, schedule, and other appendix attached to this Agreement and referred to herein is hereby incorporated in this Agreement by reference.

* * * * *

SIGNATURE PAGE

IN WITNESS WHEREOF, the undersigned have executed this Agreement as of the day and year first written above.

MANAGING GENERAL PARTNER	INITIAL LIMITED PARTNER
Petroleum Development Corporation 103 East Main Street Bridgeport, West Virginia 26330	Steven R. Williams 103 East Main Street Bridgeport, West Virginia 26330
By:________________________ Steven R. Williams Chief Executive Officer	________________________ Steven R. Williams

INVESTOR PARTNERS

COMPLETE TO INVEST AS ADDITIONAL GENERAL PARTNER

ADDITIONAL GENERAL PARTNER(S)

NUMBER OF UNITS PURCHASED

____

SUBSCRIPTION PRICE

$____________________

Name:________________________
(Print Name)

____
(Signature)

Address: ________________________

____

By: Petroleum Development Corporation

By:____________________
Its____________________
Attorney-in-Fact

COMPLETE TO INVEST AS LIMITED PARTNER

LIMITED PARTNER(S)

NUMBER OF UNITS PURCHASED

____

SUBSCRIPTION PRICE

$____________________

Name:________________________
(Print Name)

____
(Signature)

Address: ________________________

____

By: Petroleum Development Corporation

By:______________________________
Its____________________________
Attorney-in-Fact

EXHIBIT A

TO

AGREEMENT OF LIMITED PARTNERSHIP
OF
PDC 2004-___ LIMITED PARTNERSHIP,
[PDC 2005- LIMITED PARTNERSHIP]
[PDC 2006- LIMITED PARTNERSHIP]
A WEST VIRGINIA LIMITED PARTNERSHIP

Names and Addresses of Investors	Nature of Interest	Number of Units

APPENDIX B TO PROSPECTUS

PDC 2004-2006 DRILLING PROGRAM
SUBSCRIPTION AGREEMENT
PDC 2004- Limited Partnership
[PDC 2005- Limited Partnership]
[PDC 2006- Limited Partnership]

I hereby agree to purchase ______ Unit(s) in the PDC 2004- Limited Partnership [PDC 2005- Limited Partnership; PDC 2006- Limited Partnership] (the "Partnership") at $20,000 per Unit. Enclosed please find my check in the amount of $________. My completion and execution of this Subscription Agreement also constitutes my execution of the Limited Partnership Agreement and the Certificate of Limited Partnership of the Partnership. If this Subscription is accepted, I agree to be bound and governed by the provisions of the Limited Partnership Agreement of the Partnership. With respect to this purchase, I am aware that a broker may sell Units to me only if I qualify according to the express suitability standards stated herein and in the Prospectus, and I represent that:

i. I have received a copy of the Prospectus for the Partnership.

ii. I have a net worth of not less than $225,000 (exclusive of home, furnishings and automobiles); or I have a net worth of not less than $60,000 (exclusive of home, furnishings and automobiles) and had during my last tax year or estimate that I will have 2005 taxable income as defined in Section 63 of the Internal Revenue Code of 1986 of at least $60,000, without regard to an investment in the Partnership.

iii. If a resident of Alabama, Alaska, Arizona, Arkansas, California, Indiana, Iowa, Kansas, Kentucky, Maine, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Dakota, Tennessee, Texas, Vermont, or Washington, I am aware of and satisfy the additional suitability and other requirements stated in Appendix C to the Prospectus.

iv. If a resident of California, I acknowledge and understand that the offering may not comply with all the rules set forth in Title 10 of the California Administrative Code; the following are some, but not necessarily all, of the possible deviations from the California rules: Program selling expenses may exceed the established limit; and the compensation formula varies from the California rules. Even in light of such non-compliance, I affirmatively state that I still want to invest in the Partnership.

v. Except as set forth in (f) below, I am purchasing Units for my own account.

vi. If a fiduciary, I am purchasing for a person or entity having the appropriate income and/or net worth specified in (b) or (c) above.

vii. I certify that the number shown as my Social Security or Taxpayer Identification Number on the signature page is correct.

The above representations do not constitute a waiver of any rights that I may have under the statutes administered by the Securities and Exchange Commission or by any state regulatory agency administering statutes bearing on the sale of securities.

<u>**The Managing General Partner may not complete a sale of Units to an investor until at least five business days after the date the investor receives a final Prospectus. In addition, the Managing General Partner will send each investor a confirmation of purchase.**</u>

NOTICES

i. The purchase of Units as an Additional General Partner involves a risk of unlimited liability to the extent that the Partnership's liabilities exceed its insurance proceeds, the Partnership's assets, and indemnification by the Managing General Partner, as described in "Risk Factors" in the Prospectus.

ii. The NASD requires the Soliciting Dealer or registered representative to inform potential investors of all pertinent facts relating to the liquidity and marketability of the Units, including the following: (A) the risks involved in the offering, including the speculative nature of the investment and the speculative nature of drilling for oil and natural gas; (B) the financial hazards involved in the offering, including the risk of losing my entire investment; (C) the lack of a public trading market for the Units and the lack of liquidity of this investment; (D) the restrictions on transferability of the Units; and (E) the tax consequences of the investment.

iii. The investment in the Units is not liquid.

Investors are required to execute their own subscription agreements. The Managing General Partner will not accept any subscription agreement that has been executed by someone other than the investor or in the case of fiduciary accounts by someone who does not have the legal power of attorney to sign on the investor's behalf.

Signature and Power of Attorney

I hereby appoint Petroleum Development Corporation, with full power of substitution, my true and lawful attorney to execute, file, swear to and record any Certificate(s) of Limited Partnership or amendments thereto (including but not limited to any amendments filed for the purpose of the admission of any substituted Partners) or cancellation thereof, including 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 purpose necessary to implement the Limited Partnership Agreement, and as more fully described in Article X of the Limited Partnership Agreement.

If a resident of California, I am aware of and satisfy the additional suitability requirements stated in Appendix C to the Prospectus and acknowledge the receipt of California Rule 260.141.11 at pages C-2, C-3, C-4 and C-5 of Appendix C to the Prospectus.

Date: ________________________, 2005.

Signature	Signature
Please Print Name	Please Print Name
Social Security or Tax Identification Number	Social Security or Tax Identification Number

I utilize the calendar year as my Federal income tax year, unless indicated otherwise as follows:.

Mailing Address:

Street

City State Zip Code

WSH\131424.1

Address for Distributions and Notices, if different from above:

Street

City State Zip Code (Account or Reference No.)
Business Telephone No. (_____) _________ Home Telephone No. (______) ________

Type of Units Purchased (check box below):

☐ Units as an Additional General Partner

IF NO SELECTION IS MADE, WE CANNOT ACCEPT YOUR SUBSCRIPTION AND WILL HAVE TO RETURN THIS SUBSCRIPTION AGREEMENT AND YOUR MONEY TO YOU.

☐ Units as a Limited Partner

Title to Units to be held (check box below):

☐ Individual Ownership

☐ Joint Tenants with Right of Survivorship (both persons must sign)

☐ Tenants in Common (both persons must sign)

☐ Other ____

TO BE COMPLETED BY PETROLEUM DEVELOPMENT CORPORATION

Petroleum Development Corporation, as the Managing General Partner of the Partnership, hereby accepts this Subscription and agrees to hold and invest the same pursuant to the terms and conditions of the Limited Partnership Agreement of the Partnership.

ATTEST:

____

PETROLEUM DEVELOPMENT CORPORATION

By:_______________________________________

Title:_____________________________________

Date:_____________________________________

TO BE COMPLETED BY REGISTERED REPRESENTATIVE
(For Commission and Other Purposes)

I hereby represent that I have discharged my affirmative obligations under Sections 2(B) and 3(D) of Rule 2810(b) of the NASD Conduct Rules and specifically have obtained information from the above-named subscriber concerning his/her net worth, annual income, federal income tax bracket, investment portfolio and other financial information and have determined that an investment in the Partnership is suitable for such subscriber, that such subscriber is or will be in a financial position to realize the benefits of this investment, and that such subscriber has a fair market net worth sufficient to sustain the risks for this investment. I have also informed the subscriber of all pertinent facts relating to the liquidity and marketability of an investment in the Partnership, of the risks of unlimited liability regarding an investment as an Additional General Partner, and of the passive loss limitations for tax purposes of an investment as a Limited Partner.

Name of Brokerage Firm	Office Number FC RR AE Number
Registered Representative Office Address	FC RR AE Name (Please Print)
City State Zip Code	FC RR AE Social Security Number
Area Code Telephone Number	_____________________________, 2005 FC RR AE Signature Date

WSH\131424.1

APPENDIX C TO PROSPECTUS

PDC 2004-2006 DRILLING PROGRAM
SPECIAL SUBSCRIPTION INSTRUCTIONS

Checks for Units should be made payable to "BB&T as Escrow Agent for PDC 2004- Limited Partnership" [PDC 2005- Limited Partnership; PDC 2006- Limited Partnership] and should be given to the subscriber's broker for submission to the Dealer Manager and Escrow Agent. The minimum subscription is $5,000. Subscriptions are payable only in cash upon subscription. In the event that a subscriber purchases Units in a particular Partnership on more than one occasion during an offering period, the minimum purchase on each occasion is $5,000 (one-quarter Unit).

Signature Requirement.

Investors are required to execute their own subscription agreements. The Managing General Partner will not accept any subscription agreement that has been executed by someone other than the investor or in the case of fiduciary accounts someone who does not have the legal power of attorney to sign on the investor's behalf.

Notice to Alaska Investors.

An Alaska investor must be (1) a person whose total purchase does not exceed 5% of his/her net worth if the purchase of securities is at least $10,000, and must have (2) either: (a) a minimum annual gross income of $60,000 and a minimum net worth of $60,000, exclusive of principal automobile, principal residence, and home furnishings, or (b) a minimum net worth of $225,000, exclusive of principal automobile, principal residence, and home furnishings.

Registration of Securities in Minnesota.

The Program received an order of effectiveness on February 10, 2004 from the Registration Division of the Minnesota Department of Commerce permitting the Program to sell its securities to Minnesota investors. Under the laws of Minnesota, this license is effective for two years from its date of grant. Consequently, the Program will be permitted to continue to sell its securities to Minnesota investors until February 10, 2004. Prior to that date, the Program will submit its application to the Registration Division to register its securities in Minnesota for the remainder of 2006. Until the Program is granted a license to permit it to sell its securities after February 10, 2006, the Program will not effect any sales after that date. The Program's offering will terminate on December 31, 2006.

Notice to New Hampshire Investors.

If a New Hampshire resident, I have either: (1) a net worth of not less than $250,000 (exclusive of home, furnishings, and automobiles), or (2) a net worth of not less than $125,000 (exclusive of home, furnishings and automobiles), and $50,000 in taxable income.

Subscribers of Limited Partnership Interests:

If a North Carolina resident, I have either: (1) a net worth of not less than $225,000 (exclusive of home, furnishings and automobiles), or (2) a net worth of not less than $60,000 (exclusive of home, furnishings and automobiles) and an estimated taxable income as defined in Section 63 of the Internal

Revenue Code of 1986 of $60,000 or more without regard to an investment in a Partnership in 2005 for Partnerships designated "PDC 2005- Limited Partnership."

If a Pennsylvania or South Dakota resident, I have either: (1) a net worth of at least $225,000 (exclusive of home, furnishings and automobiles) or (2) a net worth of at least $60,000 (exclusive of home, furnishings and automobiles) and a taxable income in 2004 for Partnerships designated PDC 2005- Limited Partnership of $60,000 or estimate that I will have an annual taxable income of $60,000 during my current tax year; or that I am purchasing in a fiduciary capacity for a person or entity having such net worth or such taxable income. My investment in the Partnership will not be equal to or more than 10% of my net worth.

Subscribers of Additional General Partnership Interests:

Except as otherwise provided below, if a resident of Alabama, Arizona, Arkansas, Indiana, Iowa, Kansas, Kentucky, Maine, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Vermont, or Washington, I (1) have an individual or joint minimum net worth with my spouse of $225,000, without regard to the investment in the program, (exclusive of home, home furnishings and automobiles) and a combined minimum gross income of $100,000 or more for the current year and for the two previous years; notwithstanding the foregoing, as an investor in Arizona, Indiana, Iowa, Kansas, Kentucky, Michigan, New Mexico, Oklahoma, Oregon, Vermont and Washington, I have an individual or joint minimum net worth (exclusive of home, home furnishings, and automobiles) with my spouse of $225,000, without regard to an investment in the Program, and an individual or combined taxable income of $60,000 or more for the previous year and in expectation of an individual or combined taxable income of $60,000 or more for each of the current year and the succeeding year; or (2) have an individual or joint minimum net worth with my spouse in excess of $1,000,000, inclusive of home, home furnishings and automobiles; or (3) have an individual or joint minimum net worth with my spouse in excess of $500,000, exclusive of home, home furnishings and automobiles; or (4) have a combined minimum gross income of $200,000 in the current year and the two previous years.

If resident of South Dakota, I (1) have net worth, or a joint net worth with my spouse, of not less than $1,000,000 at the time of the purchase or (2) have an individual income in excess of $200,000 in each of the two most recent years or joint income with my spouse in excess of $300,000 in each of those years and have a reasonable expectation of reaching the same income level in the current year; or (3) have an individual or joint minimum net worth (exclusive of home, home furnishings, and automobiles) with my spouse of $225,000, without regard to an investment in the Program, and an individual or combined taxable income of $60,000 or more for the previous year and an expectation of an individual or combined taxable income of $60,000 or more for each of the current year and the succeeding year.

If I am a Michigan, Missouri, New Mexico, Ohio, Pennsylvania, or South Dakota resident, my investment in the Partnership will not be equal to or more than 10% of my net worth.

ATTENTION CALIFORNIA INVESTORS

A resident of California who subscribes for Units of general partnership interest must represent that he (1) has a net worth of not less than $250,000 (exclusive of home, furnishings and automobiles) and had annual gross income during 2004 for Partnerships designated "PDC 2005- Limited Partnership" of $120,000 or more, or expects to have gross income in 2005 for Partnerships designated "PDC 2005- Limited Partnership of $120,000 or more, or (2) has a net worth of not less than $500,000 (exclusive of home, furnishings and automobiles), or (3) has a net worth of not less than $1,000,000, or (4) expects to have gross income in 2005 for Partnerships designated "PDC 2005- Limited Partnership" of not less than $200,000.

A resident of California who subscribes for Units of limited partnership interest must represent that he (1) has a net worth of not less than $250,000 (exclusive of home, furnishings and automobiles) and expects to have gross income in 2005 for Partnerships designated "PDC 2005- Limited Partnership" of $65,000 or more, or (2) has net worth of not less than $500,000 (exclusive of home, furnishings and automobiles), or (3) has a net worth of not less than $1,000,000, or (4) expects to have gross income in 2005 for Partnerships designated "PDC 2005- Limited Partnership of not less than $200,000.

If a resident of California, I am aware that:

It is unlawful to consummate a sale or transfer of this security, or any interest therein, or to receive any consideration therefor, without the prior written consent of the Commissioner of Corporations of the State of California, except as permitted in the Commissioner's rules.

As a condition of qualification of the Units for sale in the State of California, the following rule is hereby delivered to each California purchaser.

California Administrative Code, Title 10, CH. 3, Rule 260.141.11. Restriction on transfer. (a) The issuer of a security upon which a restriction on transfer has been imposed pursuant to Sections 260.102.6, 260.102.141.10, and 260.534.10 shall cause a copy of this Section to be delivered to each issuee or transferee of such security at the time the certificate evidencing the security is delivered to the issuee or transferee.

(b) It is unlawful for the holder of any such security to consummate a sale or transfer of such security, or any interest therein, without the prior written consent of the Commissioner (until this condition is removed pursuant to Section 260.141.12 of these rules), except:

to the issuer;

pursuant to the order or process of any court;

to any person described in Subdivision (i) of Section 25102 of the Code or Section 260.105.14 of these rules;

to the transferor's ancestors, descendants or spouse, or any custodian or trustee for the account of the transferor's ancestors, descendants, or spouse; or to a transferee by a trustee or custodian for the account of the transferee or the transferee's ancestors, descendants or spouse;

to the holders of securities of the same class of the same issuer;

by way of gift or donation intervivos or on death;

by or through a broker-dealer licensed under the Code (either acting as such or as a finder) to a resident of a foreign state, territory or country who is neither domiciled in this state to the knowledge of the broker-dealer, nor actually present in this state if the sale of such securities is not in violation of any securities law of the foreign state, territory or country concerned;

to a broker-dealer licensed under the Code in a principal transaction, or as an underwriter or member of an underwriting syndicate or selling group;

if the interest sold or transferred is a pledge or other lien given by the purchaser to the seller upon a sale of the security for which the Commissioner's written consent is obtained or under this rule not required;

by way of a sale qualified under Section 25111, 25112, 25113 or 25121 of the Code, of the securities to be transferred, provided that no order under Section 25140 or Subdivision (a) of Section 25143 is in effect with respect to such qualification;

by a corporation to a wholly-owned subsidiary of such corporation, or by a wholly-owned subsidiary of a corporation to such corporation;

by way of an exchange qualified under Section 25111, 25112 or 25113 of the Code, provided that no order under Section 25140 or Subdivision (a) of Section 25143 is in effect with respect to such qualification;

between residents of foreign states, territories or countries who are neither domiciled nor actually present in this state;

to the State Controller pursuant to the Unclaimed Property Law or to the administrator of the unclaimed property law of another state;

by the State Controller pursuant to the Unclaimed Property Law or by the administrator of the unclaimed property law of another state if, in either such case, such person (i) discloses to potential purchasers at the sale that transfer of the securities is restricted under this rule, (ii) delivers to each purchaser a copy of this rule, and (iii) advises the Commissioner of the name of each purchaser; or

by a trustee to a successor trustee when such transfer does not involve a change in the beneficial ownership of the securities;

provided that any such transfer is on the condition that any certificate evidencing the security issued to such transferee shall contain the legend required by this section.

(c) The certificates representing all such securities subject to such a restriction on transfer, whether upon initial issuance or upon any transfer thereof, shall bear on their face a legend, prominently stamped or printed thereon in capital letters of not less than 10-point size, reading as follows:

"It is unlawful to consummate a sale or transfer of this security, or any interest therein, or to receive any consideration therefor, without the prior written consent of the Commissioner of Corporations of the State of California, except as permitted in the Commissioner's rules."

As a condition of qualification of the Units for sale in the State of California, each California subscriber through the execution of the Subscription Agreement acknowledges his understanding that the California Department of Corporations has adopted certain regulations and guidelines which apply to oil and gas interests offered to the public in the State of California.

DUANE MORRIS LLP

ATTORNEYS AT LAW

1667 K STREET N.W., SUITE 700
WASHINGTON, D.C. 20006-1608
(202) 776-7800

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(202) 776-7801

www.duanemorris.com

June 23, 2005

Petroleum Development Corporation
103 East Main Street
Bridgeport, West Virginia 26330

Re: **PDC 2004-2006 Drilling Program**

Dear Management of PDC:

We have acted as counsel for PDC 2004-2006 Drilling Program, in connection with the offer and sale of securities (the "Units") in a series of limited partnerships, PDC 2004- Limited Partnerships, PDC 2005- Limited Partnerships, and PDC 2006- Limited Partnerships (the "Partnerships") to be organized as limited partnerships under the West Virginia Uniform Limited Partnership Act and in connection with the preparation and filing with the Securities and Exchange Commission of a registration statement on Form S-1 (the "Registration Statement"). Capitalized terms used herein shall have the meaning ascribed to such terms in the Registration Statement, unless otherwise provided.

We have examined and are familiar with: (i) the Registration Statement, including a prospectus (the "Prospectus"), (ii) the Partnerships' form of limited partnership agreement (the "Partnership Agreement"), and (iii) such other documents and instruments as we have considered necessary for purposes of the opinions hereinafter set forth.

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 Managing General Partner of the Partnerships and its affiliates with respect to the factual determinations underlying the legal conclusions set forth herein, including a representation of Petroleum Development Corporation as to its net worth. 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 Partnerships. Finally, we are not expressing any opinion with respect to the amount of allowable losses or credits that may be generated by the Partnerships or the amount of each Investor Partner's share of allowable losses or credits from the Partnerships' activities.

This Appendix D to the Prospectus constitutes our opinion as to all material tax considerations of the offering. In our opinion, each of the legal conclusions rendered in this Appendix D to the Prospectus is correct in all material respects as of the date of this opinion, under the Internal Revenue Code of 1986, as amended (the "Code"), the rules and regulations promulgated thereunder, and existing interpretations thereof.

The following opinion and statements are based upon the provisions of the Code, existing and proposed Treasury regulations thereunder, current administrative rulings, and court decisions as of the date of this opinion. 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 as Counsel 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 being 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 Prospectus (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 Investor 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, 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

<u>Opinions expressed</u>: The following is a summary of the specific opinions expressed by us with respect to Tax Considerations discussed herein. **To be fully understood, the complete discussion of these matters should be read by each prospective Investor Partner.**

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

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

4. To the extent the Partnership's wells are timely drilled and amounts are timely paid, the Partners will be entitled to their pro rata share of the Partnership's IDC paid in 2004, with respect to Partnerships designated "PDC 2004- Limited Partnership," 2005 with respect to Partnerships designated "PDC 2005- Limited Partnership" and 2006 with respect to Partnerships designated "PDC 2006- Limited Partnership."

5. The deductibility of losses generated from the Partnership will not be limited by the at risk rules or the limitations related to an Investor's adjusted basis in his Partnership interest to the extent that the Investor contributes cash to the Partnership from "personal funds" (i.e., funds not borrowed by the Investor).

6. Additional General Partners' interests will not be considered a passive activity within the meaning of Code section 469 and losses generated while such general partner interest is so held will not be limited by the passive activity provisions.

7. Limited Partners' interests (other than those held by Additional General Partners who convert their interests into Limited Partners' interests) will be considered interests in a passive activity within the meaning of Code section 469 and losses generated therefrom will be limited by the passive activity provisions.

8. The Partnership will not be terminated solely as the result of the conversion of Partnership interests.

9. 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.

10. The Partnership will not be required to register with the Service as a tax shelter; the Partners will not be required to disclose the Partnership as a tax shelter on Form 8886; and the organizers of the Partnership will not be required to maintain a list of the Partners as participants in a tax shelter.

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

The impact of an investment in the Partnership on an Investor's alternative minimum tax.

11. 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 engaging in the Transaction.

12. Whether each Partner will be entitled to percentage depletion due to the factual nature of determining the status of the Partner as an independent producer and on the partner's other oil and gas production.

13. Without any assistance of the Managing 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. Whether any interest incurred by a Partner with respect to any borrowings will be deductible or subject to limitations on deductibility, due to the factual nature of the issue.

14. Whether the fees to be paid to the Managing General Partner and to third parties will be deductible, due to the factual nature of the issue. 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.

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, local, and self-employment tax.

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

The Partnership Agreement to be entered into by and among the Managing General Partner and Investor Partners and any amendments thereto will be duly executed and will be made available to any Investor Partner upon written request. The Partnership Agreement will be duly recorded in all places required under the West Virginia 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 Prospectus, and the Act.

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

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

The respective amounts that will be paid to the General Partners as Drilling Fees, Operating Fees, and other fees will be amounts that would not exceed amounts that would be ordinarily paid for similar transactions between Persons having no affiliation and dealing with each other at "arms' length."

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

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

The Drilling Agreement to be entered into by and among the Managing General Partner and the Partnership will be duly executed and will govern the drilling of the Partnership's Wells. All Partnership Wells will be spudded by the close of business on March 30, 2005 with respect to Partnerships designated "PDC 2004- Limited Partnership," March 30, 2006 with respect to Partnerships designated "PDC 2005- Limited Partnership," and March 30, 2007 with respect to Partnerships designated "PDC 2006- Limited Partnership." Thereafter, each well will be completed with due diligence, if completion is warranted. The entire amount to be paid to the Managing General Partner under the Drilling and Operating Agreement is attributable to Intangible Drilling and Development Costs and does not include a profit for services performed or materials provided by third parties which are passed through at actual cost.

15. The Drilling and Operating Agreement will be duly executed and will govern the operation of the Partnership's Wells.

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 Partnership will not issue additional interests after the initial offering and no Partner or person related to a Partner will provide a contemporaneous opportunity to acquire interests in a substantially identical investment. The Managing General Partner does not believe that any market will ever exist for the sale of Units and the Managing 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.

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

The Managing General Partner will not permit the purchase of Units by tax-exempt investors or foreign investors.

The Partnership will not drill, own or operate any Well located outside the United States.

No Partner will incur any debt that either is: (i) arranged by the Partnership, the Managing General Partner, or any other person who participated in the organization or management of the Partnership or the sale of Units (or any person related to such persons), or (ii) secured by any asset of the Partnership.

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 West Virginia. 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 or as an association taxable as a corporation. 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 West Virginia 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 as a corporation or as an association taxable as a corporation is based in part on entity classification regulations and in part on the fact that in our opinion the Partnership will not constitute a "publicly traded partnership."

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 Managing General Partner 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.

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). Treas. Reg. section 1.7704-1(b) provides that an "established securities market" includes a national securities exchange registered under section 6 of the Securities Exchange Act of 1934 (the "1934 Act"), a national securities exchange exempt under the 1934 Act because of the limited volume of transactions, certain foreign security laws, regional or local exchanges, and an interdealer quotation system that regularly disseminates firm buy or sell quotations by identified brokers or dealers. The Managing 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 Managing General Partner has represented that it believes that, for all taxable years of the Partnership, 90% or more of the Partnership's gross income will consist of such qualifying income.

The Service issued Treas. Reg. 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. The Regulations provide (at Treas. Reg. section 1-7704-1(e)) that certain transfers will not be treated as involving trading. Among such transfers are transfers pursuant to a “closed end redemption plan,” defined as a plan of redemption or repurchase maintained by a partnership whereby the partners may tender their interests for purchase by the partnership or a related party, as long as the partnership does not issue additional interests after the initial offering and no partner or person related to a partner provides a contemporaneous opportunity to acquire interests in substantially identical investments.

Based upon representations of the Managing General Partner relating to the lack of any market in interests in the Partnership , the Partnership, in our opinion, will not be treated as a PTP because interests therein will not be regarded as traded under the “closed end redemption plan” exception in the Regulations described above. Further, based upon representations of the Managing General Partner relating to satisfaction of the 90% gross income test describe above,, the Partnership, in our opinion, will not be treated as a corporation for federal income tax purposes under Code section 7704(c) for that additional reason.

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.

Summary

In our opinion the Partnership will not be treated as an association taxable as a corporation for federal income tax purposes by reason of the Check the Box Regulations. Further, the Partnership, in our opinion, will not be treated as a PTP or be treated as a corporation for federal income tax purposes. Accordingly, the Partnership in our opinion will be treated as a 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.

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.

TAX SHELTER RULES

The Code provides that “tax shelters” (i.e., so-called “Reportable Transactions”) must be reported to the Service in a particular manner. In addition, promoters or organizers of Reportable Transactions generally must prepare and maintain a list of each of the participants in the tax shelter. In our view, the Partnership will not be considered a Reportable Transaction as described in this "Tax Shelter Rules" section.

Every taxpayer that participates in a "Reportable Transaction" generally must disclose the transaction to the Service using Form 8886 and (ii) every organizer and seller of a "Potentially Abusive Tax Shelter" (which is generally a Reportable Transaction or a tax shelter that is required to be registered) generally must prepare and maintain a list of each of the participants in the transaction. The Service has recently issued final regulations addressing these disclosure and list maintenance requirements, which are generally effective for transactions entered into on or after February 28, 2003. See Treas. Reg. sections 1.6011-4 and 301.6112-1. A Reportable Transaction (and accordingly, by definition, a Potentially Abusive Tax Shelter) includes certain transactions that give rise to a significant book-tax difference. Treas. Reg. sections 1.6011-4(b)(6) and 301.6112-1(b)(2)(i)(B). Although the

Partnership's election to deduct IDC rather than capitalize it could give rise to a significant book-tax difference, a book-tax difference caused by deducting IDC pursuant to Code section 263(c) is not taken into account for these purposes. Rev. Proc. 2003-25, section 4.04, 2003-11 I.R.B. 601 (February 27, 2003). In addition, the Partnership does not otherwise satisfy the definition of a Reportable Transaction. Therefore, it is our view that an investment in the Partnership will not be a Reportable Transaction. Furthermore, the Partnership will not be a Potentially Abusive Tax Shelter because an investment in the Partnership will not be a Reportable Transaction and because the Partnership will not be a tax shelter that is required to be registered. Consequently, the Partners will not be required to disclose the Partnership as a tax shelter on Form 8886 and the organizers of the Partnership will not be required to maintain a list of the Partners as participants in a tax shelter.

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, 503 U.S. 79 (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 Treasury Secretary 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(c). 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. The Managing General Partner has represented that the Partnership will elect to deduct IDC in accordance with Treas. Reg. section 1.612-4. In this regard, Additional General Partners generally will be entitled to deduct IDC against any form of income in the year in which the investment is made, provided wells are spudded within the first ninety days of the following year; subject to the same provision, Limited Partners generally will be entitled to deduct IDC against passive income. See discussions below concerning passive loss and credit limitations and alternative minimum tax, which may limit the benefit of an IDC deduction.

Classification of Costs

In general, IDC consists of those costs which in and of themselves have no salvage value. Treas. Reg. section 1.612-4(a) provides examples of items to which the option to deduct IDC applies, including all amounts paid for labor, fuel, repairs, hauling, and supplies, or any of them, which are used (i) in the drilling, shooting, and cleaning of wells, (ii) in such clearing of ground, draining, road making, surveying, and geological works as are necessary in the preparation for the drilling of wells, and (iii) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. The Service, in Rev. Rul. 70-414, 1970-2 C.B. 132, set forth further classifications of items subject to the option and those considered capital in nature. The ruling provides that the following items are not subject to the election of Treas. Reg. section 1.612-4(a): (i) oil well pumps (upon initial completion of the well), including the necessary housing structures; (ii) oil well pumps (after the well has flowed for a time), including the necessary housing structures; (iii) oil well separators, including the necessary housing structures; (iv) pipelines from the wellhead to oil storage tanks on the producing lease; (v) oil storage tanks on the producing lease; (vi) salt water disposal equipment, including any necessary pipelines; (vii) pipelines from the mouth of a gas well to the first point of control, such as a common carrier pipeline, natural gasoline plant, or carbon black plant; (viii) recycling equipment, including any necessary pipelines; and (ix) pipelines from oil storage tanks on the producing leasehold to a common carrier pipeline.

A partnership's classification of a cost as IDC is not binding on the government, which might reclassify an item labeled as IDC as a cost which must be capitalized. In Bernuth v. Commissioner, 57 T.C. 225 (1971), aff'd, 470 F.2d 710 (2nd Cir. 1972), the Tax Court denied taxpayers a deduction for that portion of a turnkey drilling contract price that was in excess of a reasonable cost for drilling the wells in question under a turnkey contract, holding that the amount specified in the turnkey contract was not controlling. Similarly, the Service, in Rev. Rul. 73-211, 1973-1 C.B. 303, concluded that excessive turnkey costs are not deductible as IDC:

> [O]nly that portion of the amount of the taxpayer's total investment that is attributable to intangible drilling and development costs that would have been incurred in an arm's-length transaction with an unrelated drilling contractor (in accordance with the economic realities of the transaction) is deductible [as IDC].

To the extent the Partnership's prices meet the reasonable price standards imposed by Bernuth, supra, and Rev. Rul 73-211, supra, and to the extent such amounts are not allocable to tangible property, leasehold costs, and the like, the amounts paid to the Managing General Partner under the drilling contract 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 Managing General Partner 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 agreement, 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 Managing General Partner 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 of their interests in the Partnership.

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 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 Managing 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." "Tax shelter," for purposes of Code section 461, is defined to 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 Managing General Partner has represented that, as Operator, it will commence drilling operations by spudding each well on or before March 30, 2005 for Partnerships designated "PDC 2004- Limited Partnership," March 30, 2006 for Partnerships designated "PDC 2005- Limited Partnership," and March 30, 2007 for Partnerships designated "PDC 2006- Limited Partnership," and will complete each well, if completion is warranted, with due diligence thereafter. Further, the Managing 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 substantial 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 Managing General Partner is unable to represent that all of the Wells will be completed in 2004 for Partnerships designated "PDC 2004- Limited Partnership," 2005 for Partnerships designated "PDC 2005- Limited Partnership," and 2006 for Partnerships designated "PDC 2006- Limited Partnership"; however, the Managing General Partner has represented that any Well that is not completed in 2004 with respect to Partnerships designated "PDC 2004- Limited Partnership," in 2005 with respect to Partnerships designated "PDC 2005- Limited Partnership," and in 2006 with respect to Partnerships designated "PDC 2006- Limited Partnership" will be spudded by not later than March 30, 2005 for Partnerships designated "PDC 2004- Limited Partnership," March 30, 2006 for Partnerships designated "PDC 2005- Limited Partnership," and March 30, 2007 for Partnerships designated "PDC 2006- Limited Partnership," respectively.

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 the Drilling and Operating Agreement, if amounts paid by the Partnership prior to the commencement of drilling exceed amounts due the Managing General Partner thereunder, the Managing General Partner will not refund any portion of amounts paid by the Partnership, but rather will create a credit once the actual costs incurred by the Managing General Partner are compared to the amounts paid. Further, the Managing General Partner will expend such credit for additional IDC on additional wells selected by the Managing General Partner.

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 adopted 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, supra, 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 Managing General Partner has represented that the Drilling and Operating Agreement to be entered into with PDC by the Partnership will be duly executed by and delivered to PDC, the

Partnership, and PDC as attorney-in-fact for the Partners and will govern the drilling, and, if warranted, the completion of each of the Wells. The Drilling and Operating Agreement requires PDC to commence drilling operations by spudding each Well on or before March 30, 2005 for Partnerships designated "PDC 2004- Limited Partnership," March 30, 2006 for Partnerships designated "PDC 2005- Limited Partnership," and March 30, 2007 for Partnerships designated "PDC 2006- Limited Partnership," and to complete each Well, if completion is warranted, with due diligence thereafter. Also, under the terms of the Drilling and Operating Agreement, PDC, as general contractor, will not refund any portion of amounts paid in the event actual costs are less than the amounts paid but will apply any such amounts solely for payment of additional drilling services to the Partners. Based upon this representation and others included within the opinion and assuming that the Drilling and Operating Agreement will be performed in accordance with its terms, we are of the opinion that the payment for IDC under the Drilling and Operating Agreement, if made in 2004 for Partnerships designated "PDC 2004- Limited Partnership," 2005 for Partnerships designated "PDC 2005- Limited Partnerships," and 2006 for Partnerships designated "PDC 2006- Limited Partnership" will be allowable as a deduction in 2004 for Partnerships designated "PDC 2004- Limited Partnership," 2005 for Partnerships designated "PDC 2005- Limited Partnerships," and 2006 for Partnerships designated "PDC 2006- Limited Partnership" subject to the other limitations discussed in this opinion. Although PDC will attempt to satisfy each requirement of the Service and judicial authority for deductibility of IDC in 2004 for Partnerships designated "PDC 2004- Limited Partnership," 2005 for Partnerships designated "PDC 2005- Limited Partnerships," and 2006 for Partnerships designated "PDC 2006- Limited Partnership" no assurance can be given that the Service will not successfully contend that the IDC of a well which is not completed until 2005 for Partnerships designated "PDC 2004- Limited Partnership," 2006 for Partnerships designated "PDC 2005- Limited Partnership," and 2007 for Partnerships designated "PDC 2006- Limited Partnership" are not deductible in whole or in part until 2005 or 2006 or 2007, respectively. Further, to the extent drilling of the Partnership's wells does not commence by March 30, 2005 for Partnerships designated "PDC 2004- Limited Partnership," March 30, 2006 for Partnerships designated "PDC 2005- Limited Partnership," and March 30, 2007 for Partnerships designated "PDC 2006- Limited Partnership," the deductibility of all or a portion of the IDC may be deferred under Code section 461.

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 deduction equal to 15% of the taxpayer's gross income from the property is generally allowed in any taxable year, in general 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). In the case of "stripper well property," as that term is defined in Code section 613A(c)(6)(D), the 100% of taxable income limitation has been eliminated for taxable years 1998 to 2003. Code section 613A(c)(6)(H). Proposed legislation would extend this provision through 2004. It is anticipated that the properties of the Partnerships will likely constitute "stripper well properties" for this purpose. In the case of production from marginal properties, the percentage depletion rate may be increased up to 25% depending upon the reference price for crude oil in the preceding year. Code 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 Code section 1254.

Since the availability of percentage depletion for a Partner is dependent upon the status of the partner as an independent producer, we also are unable to express an opinion on this matter. Because of the

foregoing, 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.

For certain tangible property, the Partnership will be allowed an additional depreciation deduction equal to 50% of the adjusted basis of the property for the year in which the property is placed in service. Code section 168(k)(1). The adjusted basis of the property must be reduced by the additional depreciation deduction before computing the amount otherwise allowable as a depreciation deduction for the tax year in which the property is placed in service and all later years. In order to be entitled to this deduction, the Partnership generally must purchase the property and place it in service before January 1, 2005. Code section 168(k).

INTEREST DEDUCTIONS

In the Transaction, the Investor Partners will acquire their interests by remitting cash in the amount of $20,000 per Unit to the Partnership. In no event will the Partnership accept notes in exchange for a Partnership interest. Nevertheless, without any assistance of the Managing 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 (the "Fees") to be paid to third parties and to the Managing General Partner or to the Operator and its affiliates (as described in the Prospectus under "Source of Funds and Use of Proceeds") 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 counsel expresses 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 prospectus 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 (I) investigating the creation or acquisition of an active trade or business, (II) creating an active trade or business, or (III) 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 payments to the Managing General Partner, as described in greater detail in the Prospectus. 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 Prospectus are considered syndication costs (such as the fees paid to brokers and broker-dealers, and the fees paid for printing the Prospectus and possibly all or a portion of the Managing General Partner's management fee), 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 Managing General Partner's allocations, a Partner's taxable income could be increased, thereby resulting in increased taxes and in 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. Code section 704(d). 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) distributions of cash and the adjusted basis of property other than cash made to him, and (iv) his share of reduction in the amount of indebtedness previously included in his basis. Treas. Reg. section 1.705-1(a)(1).

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 (I) is personally liable for the repayment of such amounts, or (II) 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, with some modifications, 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 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 limitations related to adjusted basis will limit the deductibility of losses generated from the Partnership.

PASSIVE LOSS AND CREDIT LIMITATIONS

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 Temp. 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.

General Partner Interests

Due to the factual nature of the applicability of the material participation factors to an Additional General Partner's participation in the activities of the Partnership, we cannot express an opinion with respect to whether such participation will be material. However, the "working interest" exception to the passive activity rules applies without regard to the level of the taxpayer's participation. Nevertheless, the presence or absence of material participation may be relevant for purposes of determining whether the investment interest expense rules of Code section 163(d) apply to limit the deductibility of interest incurred in connection with any borrowings of an Additional General Partner.

As noted above, 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 taxpayer's liability with respect to such interest. Temp. Treas. Reg. section 1.469-1T(e)(4)(v) describes an interest in an entity that limits a taxpayer's liability with respect to the drilling or operation of a well as (i) a limited partnership interest in a partnership in which the taxpayer is not a general partner, (ii) stock in a corporation, or (iii) an interest in any other entity that, under applicable state law, limits the interest holder's potential liability. For purposes of this provision, indemnification agreements, stop loss arrangements, insurance, or any similar arrangements or combinations thereof are not taken into account in determining whether a taxpayer's liability is limited. Id.

The Joint Committee on Taxation's General Explanation of the Tax Reform Act of 1986 (the "Bluebook") indicates that a "working interest" is an interest with respect to an oil and gas property that is burdened with the cost of development and operation of the property, and that generally has characteristics such as responsibility for signing authorizations for expenditures with respect to the activity, receiving periodic drilling and completion reports and reports regarding the amount of oil extracted, voting rights proportionate to the percentage of the working interest possessed by the taxpayer, the right to continue activities if the present operator decides to discontinue operations, a proportionate share of tort liability with respect to the property and some responsibility to share in further costs with respect to the property in the event a decision is made to spend more than amounts already contributed. The Regulations define a working interest as "a working or operating mineral interest in any tract or parcel of land (within the meaning of section 1.612-4(a))." Treas. Reg. section 1.469-1(e)(4)(iv). Under Treas. Reg. section 1.614-2(b), an operating mineral interest is defined as

> a separate mineral interest as described in section 614(a), in respect of which the costs of production are required to be taken into account by the taxpayer for purposes of computing the limitation of 50 percent of the taxable income from the property in determining the deduction for percentage depletion computed under section 613, or such costs would be so required to be taken into account if the . . . well . . . were in the production stage. The term does not include royalty interests or similar interests, such as production payments or net profits interests. For the purpose of determining whether a mineral interest is an operating mineral interest, "costs of production" do not include intangible drilling and development costs, exploration expenditures under section 615, or development expenditures under section 616. Taxes, such as production taxes, payable by holders of nonoperating interests are not considered costs of production for this purpose. A taxpayer may not aggregate operating mineral interests and nonoperating mineral interests such as royalty interests.

The Managing General Partner has represented that the Partnership will acquire and hold only operating mineral interests, as defined in Code section 614(d) and the regulations thereunder, and that none of the Partnership's revenues will be from non-working interests.

To the extent that the Additional General Partners (in their capacity as general partners) have working interests in the activities of the Partnership for purposes of Code section 469, we are of the opinion that an Additional General Partner's interest in the Partnership (as a general partner) generally will not be considered a passive activity within the meaning of Code section 469 and losses generated while such general partner interest is held will not be limited by the passive activity provisions.

Notwithstanding this general rule, however, if an Additional General Partner interest is converted to a limited partner interest prior to the spudding date, but after the end of the taxable year in which IDC was incurred, IDC will be subject to the passive activity rules. See Temp. Treas. Reg. section 1.469-1T(e)(4). In addition, that portion of Partnership gross income for such prior taxable year attributable to IDC treated as passive loss will be considered passive income. The "spudding date" is the date that drilling commences.

Notwithstanding the above, there can be no assurance that the Service will not contend that all general partner interests should be regarded as interests in a passive activity from the Partnership's inception due to the conversion feature contained in the Partnership Agreement. However, due to the exposure to unlimited liability for Partnership obligations incurred prior to such conversion, an attack by the Service with respect to the foregoing should not be successful. In addition, the Service, as shown in Temp. Treas. Reg. section 1.469-1T(e)(4)(iii), example (1), respects the nature of a general partnership interest prior to its conversion into limited partnership form:

> A, a calendar year individual, acquires on January 1, 1987, a general partnership interest in P, a calendar year partnership that holds a working interest in an oil or gas property. Pursuant to the partnership agreement, A is entitled to convert the general partnership interest into a limited partnership interest at any time. On December 1, 1987, pursuant to a contract with D, an independent drilling contractor, P commences drilling a single well pursuant to the working interest. Under the drilling contract, P pays D for the drilling only as the work is performed. All drilling costs are deducted by P in the year in which they are paid. At the end of 1987, A converts the general partnership interest into a limited partnership interest, effective immediately. The drilling of the well is completed on February 28, 1988.

Since, in the example, A holds the working interest through an entity that does not limit A's liability throughout 1987 and through an entity that does limit A's liability in 1988, the example in the regulation concludes that A's interest in P's well is not an interest in a passive activity for 1987 but is an interest in a passive activity for 1988. Although the example in the regulation refers to the years 1987 and 1988, it is currently applicable.

If an Additional General Partner converts his interest to a Limited Partner interest pursuant to the terms of the Partnership Agreement, the character of a subsequently generated tax attribute will be dependent upon, inter alia, the nature of the tax attribute and whether there arose, prior to conversion, losses to which the working interest exception applied.

Assuming the activities of a converting partner will not result in the Partner's being treated as materially participating under Temp. Treas. Reg. section 1.469-5T(a)(1), (5), or (6), as described above, the Limited Partner's activity after conversion should be treated as a passive activity. Code section 469(c)(1). Accordingly, any loss arising therefrom should be treated as a PAL under Code section 469(d), with the benefits thereof limited by Code section 469(a)(1), as described above. However, Code section 469(c)(3)(B) provides that, if a taxpayer has any loss from any taxable year from a working interest in any oil or gas property that is treated as a non-passive loss, then any net income from such property for any succeeding taxable year is to be treated as income that is not from a passive activity. Consequently, assuming that a converting Additional General Partner has losses from working interests which are treated as non-passive, net income from the Partnership allocable to the Partner after conversion would be treated as income that is not from a passive activity.

Limited Partner Interests

If an Investor Partner (other than an Additional General Partner who converts his interest into that of a Limited Partner) invests in the Partnership as a Limited Partner, in the opinion of counsel, his distributive share of the Partnership's losses will be treated as PALs, the availability of which will be limited to the Partner's passive income for such year. If the Partner does not have sufficient passive income to utilize the PAL, the disallowed PAL 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(l)(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.

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.

CONVERSION OF INTERESTS

Code section 708 provides that a partnership will be considered as terminated for federal income tax purposes if, inter alia, there is "a sale or exchange of 50 percent or more of the total interest in partnership capital and profits" within a 12 month period. If a conversion of an Additional General Partner's interest into a Limited Partner interest were treated as a "sale or exchange" for purposes of Code section 708, the Partnership would be terminated for federal income tax purposes if 50% or more of the profits and capital interests in the Partnership were sold or exchanged within a 12 month period.

In Rev. Rul. 84-52, 1984-1 C.B. 157, the Service ruled that the conversion of a general partnership interest into a limited partnership interest in the same partnership will not give rise to the recognition of gain or loss under Code section 741 or section 1001. The holding of Rev. Rul. 84-52 was confirmed in Rev. Rul. 95-37, 1995-1 C.B. 130. The ruling noted that, under Code section 721, no gain or loss is recognized by a partnership or any of its partners upon the contribution of property to the partnership in exchange for an interest therein. Consequently, the partnership will not be terminated under Code section 708 since (i) the business of the partnership will continue after the conversion and (ii) pursuant to Treas. Reg. section 1.708-1(b)(2) a transaction governed by Code section 721 is not treated as a sale or exchange for purposes of Code section 708.

Assuming that Rev. Rul. 84-52, supra, is not overruled, revoked, or modified, the Partnership, in our opinion, will not be terminated under Code section 708 solely as a result of the conversion of Partnership interests.

Code section 752(b) treats any decrease in a partner's share of partnership liabilities as a distribution of money to the partner by the partnership. If, under the applicable regulatory or statutory provisions, a converting partner's share of liabilities is deemed to decrease, such decrease will result in gain to the partner to the extent it exceeds the partner's basis in his partnership interest.

As discussed above under the heading "Passive Loss and Credit Limitations," an Additional General Partner's interest in the Partnership generally will not be subject to the passive activity loss rules. However, if an Additional General Partner interest is converted to a limited partner interest prior to the spudding date, but after the end of the taxable year in which IDC was incurred, IDC will be subject to the passive activity rules. If the conversion were to occur after the filing of the Partnership's information tax return but prior to the completion of the drilling and development of a well, an amended return might have to be filed, which might also require the Investors to file amended returns. Further, the Code provides that if a taxpayer has any loss attributable to a working interest which is treated in any taxable year as a loss which is not from a passive activity, then any net income attributable to the working interest in any succeeding taxable year is treated as income of the taxpayer which is not from a passive activity. Accordingly, if an Additional General Partner converts his interest into a Limited Partner interest, any net income from that interest with respect to which he claimed deductions will be treated as nonpassive income.

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 for taxable years beginning in 2003 and 2004 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, (iii) $29,000 in the case of a married individual who files a separate return, and (iv) $22,500 in the case of 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).

Generally, the corporate AMT is similar to that of the individual AMT, with the corporation's regular taxable income increased or decreased by certain adjustments and items of tax preference, resulting in AMTI. The AMTI is reduced by $40,000 (which amount is phased-out as AMTI increases from $150,000 to $310,000) with the balance being taxed at twenty percent (20%). Code section 55(b), (d). The excess of this figure over the regular tax liability is the AMT. Certain small corporations are exempt from AMT. Code section 55(e).

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 (or, with certain adjustments, equal to the entire AMT in the case of corporate AMT) for use against the taxpayer's future regular tax liability (but not the minimum tax liability). Code section 53.

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:

Generally, taxpayers who pay or incur IDC in the development of domestic oil or gas production may elect to either expense or capitalize these amounts. Code section 263(c). If an Investor Partner elects to deduct IDC, the difference between the amount of a Partner's IDC deduction and the amount which would have been currently deductible had IDC been capitalized and recovered over a 10-year period (so-called "Excess IDC") is generally an item of tax preference for the AMT to the extent that this amount exceeds 65% of that Investor Partner's net income from oil and gas properties for the taxable year. Code section 57(a)(2). This preference applies to Investor Partners that are integrated oil companies and to Investor Partners that are not integrated oil companies but, as to the latter, only to the extent that the failure to apply the preference would result in a reduction of the Investor Partner's alternative minimum taxable income by more than 40%. Code section 57(a)(2)(E).

Excess depletion constitutes a preference only in the case of integrated oil companies. Code section 57(a)(1).

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). No ACE depreciation adjustment is necessary with respect to a corporate Partner for property placed in service in taxable years beginning after December 31, 1993. Code section 56(g)(4)(A)(i).

AMTI for a corporate Partner will be increased by seventy-five percent (75%) of the excess of the taxpayer's "adjusted current earnings" ("ACE") over the AMTI amount (computed without the ACE adjustment and without the net operating loss deduction). Code section 56(g)(1). As noted above, both corporate and individual taxpayers may elect this method of amortization for regular tax purposes. For years beginning after December 31, 1992, for corporations other than integrated oil companies, the ACE adjustments for percentage depletion and IDC are repealed. Code sections 56(g)(4)(F) and (D)(i), respectively. The IDC modification applies to IDCs paid or incurred in taxable years beginning after December 31, 1992.

Due to the inherently factual nature of the applicability of the AMT to a Partner, we are unable to express an opinion with respect to such issues. Due to the potentially significant impact of a purchase of Units on an

Investor's tax liability, investors should discuss the implications of an investment in the Partnership on their regular and AMT liabilities with their tax advisors prior to acquiring Units.

GAIN OR LOSS ON SALE OF PROPERTIES

Gain from the sale or other disposition of property is realized to the extent of the excess of the amount realized therefrom over the property's adjusted basis; conversely, loss is realized in an amount equal to the excess of the property's adjusted basis over the amount realized from such a disposition. Code section 1001(a). The amount realized is defined as the sum of any money received plus the fair market value of the property (other than money) received. Code section 1001(b). Accordingly, upon the sale or other disposition of the Partnership properties, the Partners will realize gain or loss to the extent of their pro rata share of the difference between the Partnership's adjusted basis in the property at the time of disposition and the amount realized upon disposition. In the absence of nonrecognition provisions, any gain or loss realized will be recognized for federal income tax purposes.

Gain or loss recognized upon the disposition of property used in a trade or business and held for more than one year will be treated as long term capital gain or as ordinary loss. Code section 1231(a). Currently, for individual taxpayers, the maximum federal income tax rate on long-term capital gains is generally 15%, while the maximum federal income tax rate on ordinary income is 35%. Code sections 1(h)(1)(C) and 1(i). Notwithstanding the above, however, 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 (I) all IDC previously deducted and (II) 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 (I) the recomputed basis of the property, or (II) 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).

Unrecaptured section 1250 gain may result from the recapture of depreciation related to the sale of the Partnership's section 1250 property held for more than one year. Code section 1(h)(7). Currently, unrecaptured section 1250 gain is taxed at a rate of 25%. Code section 1(h)(1)(D).

GAIN OR LOSS ON SALE OF UNITS

If 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 and short term capital gain if held 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 "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.

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(a)(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 6722 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. Code section 722. Their bases will be increased by their share of Partnership income and additional contributions and decreased by their share of Partnership losses and distributions. Code section 705(a). 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. Code section 731(a). In addition, gain could be recognized by a distributee partner upon the disproportionate distribution to that 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. Code sections 751(b) and 731. Further, the Partnership Agreement prohibits distributions to any Investor Partner to the extent such would create or increase a deficit in the Partner's Capital Account.

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 the partnership agreement to be respected. Notwithstanding these provisions, special rules apply with respect to nonrecourse deductions since, under the 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 to 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 (I) 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 (II) the partnership agreement contains a qualified income offset ("QIO") provision as provided in Treas. Reg. section 1.704-1(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 1.704-1(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. section 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 a TAM and a taxpayer's particular fact pattern, it should be noted that TAMs may not be used or cited as precedent. Code section 6110(k)(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. Treas. Reg. section 1.613A-3(e)(2). The terms "capital" and "income" are not defined in the Code or in the Regulations under Code section 613A. The 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 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 initially will be owned 78% by the Investor Partners and 22% by the Managing General Partner, IDC will be allocated 100% to the Investor Partners and other tax items will be allocated 80% to the Investor Partners. 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 Regulations under Code section 704. Nevertheless, the Service may contend that the allocation to the Investors of IDC (100%) in excess of their capital contributions (78%) or the allocation to the Managing General Partner of other tax items (100% ranging to 0% upon the occurrence of certain events) in excess of its capital contribution (22%) is invalid and may reallocate such excess IDC or other items to the other Partners. Any such reallocation could increase an Investor 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.

<u>Allocation and Distribution Shifts</u>. Section 4.02(b)(i) of the Partnership Agreement provides that the Managing General Partner will subordinate up to 50% of its 20% share of Partnership cash distributions so that the Investor Partner might receive cash distributions equal to a minimum of 12.5% per year of their Subscriptions on a cumulative basis for the first five years of Partnership well operations. Section 3.02(a) of the Partnership Agreement provides for a corresponding shift in the allocation of Partnership income.

<u>Nonrecourse Deductions</u>. As noted above, an allocation of loss or deduction attributable to nonrecourse liabilities of a partnership cannot have economic effect because the creditor alone bears any economic burden that corresponds to such an allocation. Thus, nonrecourse deductions must be allocated in accordance with the partners interests in the partnership. Treas. Reg. section 1.704-2(b)(1).

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 contains 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 Code section 704(b).

Under the Regulations, partners generally share nonrecourse liabilities in accordance with their interests in partnership profits. However, the 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 partner's interests in partnership profits.

The Partnership Agreement, at Section 3.02, 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 Treas. Reg. section 1.704-2(b)(2); second, to the extent of each such Partner's gain under Code section 704(c) if the Partnership were to dispose of (in a taxable transaction) all Partnership property subject to one or more nonrecourse liabilities of the Partnership in full satisfaction of such liabilities and for no other consideration; and third, in accordance with the Partners' proportionate shares in the Partnership's excess nonrecourse liabilities of the Partnership. Treas. Reg. section 1.752-3. For this purpose, the Partnership Agreement provides for the allocation of excess nonrecourse liabilities of 80% to the Investor Partners and 20% to the Managing 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 Treasury Secretary which take into account the varying interests of the partners during the taxable year.

The Partnership Agreement, at Section 3.04(c), 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. With respect to "allocable cash basis items," Section 3.04(c) requires an allocation in accordance with the requirements of Code section 706(d).

Accordingly, the Partnership allocations should be considered to be in accordance with the provisions of Code section 706(d).

PROFIT MOTIVE

The existence of economic, nontax motives for entering into the Transaction is essential if the Partners are to obtain the tax benefits associated with an investment in the Partnership.

Code section 183(a) provides that where an activity entered into by an individual is not engaged in for profit, no deduction attributable to that activity will be allowed except as provided therein. Should it be determined that a Partner's activities with respect to the Transaction fall within the "not for profit" ambit of Code section 183, the Service could disallow all or a portion of the deductions and credits generated by the Partnership's activities.

Code section 183(d) generally provides for a presumption that an activity is entered into for profit within the meaning of the statute where gross income from the activity exceeds the deductions attributable to such activity for three or more of the five consecutive taxable years ending with the taxable year in question. At the taxpayer's election, such presumption can relate to three or more of the taxable years in the 5-year period beginning with the taxable year in which the taxpayer first engages in the activity. Temp. Treas. Reg. section 12.9. Whether an activity is engaged in for profit is determined under Code section 162 (relating to trade or business deductions) and 212(1) and (2) (relating to income producing deductions) except insofar as the above-described presumption applies. Treas. Reg. section 1.183-1(a).

To establish that he is engaged in either a trade or business or an income producing activity, a Partner must be able to prove that he is engaged in the Transaction with an "actual and honest profit objective," Fox v. Commissioner, 80 T.C. 972, 1006 (1983), aff'd sub nom., Barnard v. Commissioner, 731 F.2d 230 (4th Cir. 1984), and that his profit objective is bona fide. Bessenyey v. Commissioner, 45 T.C. 261, 274 (1965), aff'd, 379 F.2d 252

(2d Cir. 1967), cert. denied, 389 U.S. 931 (1967). The inquiry turns on whether the primary purpose and intention of the Partner in engaging in the activity is, in fact, to make a profit apart from tax considerations. Hager v. Commissioner, 76 T.C. 759, 784. Such objective need not be reasonable, only honest, and the question of objective is to be determined from all the facts and circumstances. Sutton v. Commissioner, 84 T.C. 210 (1985), aff'd, 788 F.2d 695 (11th Cir. 1986). Among the factors that will normally be considered are: (i) the manner in which the taxpayer carries on the activity, (ii) the expertise of the taxpayer or his advisors, (iii) the time and effort expended by the taxpayer in carrying on the activity, (iv) whether an expectation exists that the assets used in the activity may appreciate in value, (v) the success of the taxpayer in carrying on similar or dissimilar activities, (vi) the taxpayer's history of income or losses with respect to the activity, (vii) the amount of occasional profits, if any, which are earned, and (viii) the financial status of the taxpayer. Treas. Reg. section 1.183-2(b). Where application of such factors to a particular activity is difficult, however, the Court will consider the totality of the circumstances instead. Estate of Baron v. Commissioner, 83 T.C. 542 (1984), aff'd, 798 F.2d 65 (2d Cir. 1986).

As noted, the issue is one of fact to be resolved not on the basis of any one factor but on the basis of all the facts and circumstances. Treas. Reg. section 1.183-2(b). Greater weight is given to objective facts than the parties' mere statements of their intent. Siegel v. Commissioner, 78 T.C. 659 (1982), Engdahl v. Commissioner, 72 T.C. 659 (1979). Nevertheless, the Courts have recognized, in applying Code section 183, that "a taxpayer has the right to engage in a venture which has economic substance even though his motivation in the early years of the venture may have been to obtain a deduction to offset taxable income." Lemmen v. Commissioner, 77 T.C. 1326, 1346 (1981), acq., 1983-2 C.B. 1.

Due to the inherently factual nature of a Partner's intent and motive in engaging in the Transaction, we do not express an opinion as to the ultimate resolution of this issue in the event of a challenge by the Service. Partners must, however, seek to make a profit from their activities with respect to the Transaction beyond any tax benefits derived from those activities or risk losing those tax benefits.

TAX AUDITS

Subchapter C of Chapter 63 of the Code provides that administrative proceedings for the assessment and collection of tax deficiencies attributable to a partnership must be conducted at the partnership, rather than the partner, level. Partners will be required to treat Partnership items of income, gain, loss, deduction, and credit in a manner consistent with the treatment of each such item on the Partnership's returns unless such Partner files a statement with the Service identifying the inconsistency. If the Partnership is audited, the tax treatment of each item will be determined at the Partnership level in a unified partnership proceeding. Conforming adjustments to the Partners' own returns will then occur unless such partner can establish a basis for inconsistent treatment (subject to waiver by the Service).

PDC 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 the requirements of Code sections 6223 and 6224 and the regulations thereunder, 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.

By executing the partnership agreement each partner respectively represents, warrants, and agrees that he will not form or exercise any right as a member of a notice group and will not file a statement notifying the Service that the TMP does not have binding settlement authority. Such waiver is permitted under the partnership audit provisions of the Code and will be binding on the Partners.

The costs incurred by a Partner in responding to an administrative proceeding will be borne solely by such Partner.

The Taxpayer Relief Act of 1997 added new sections 771-777 to the Code providing for alternative reporting treatment for partnerships and their partners in the case of partnerships having 100 or more partners. In general these provisions provide for somewhat simplified reporting of partnership items on the forms K-1 supplied to partners. The Managing General Partner has not determined whether to make the election provided pursuant to these new Code provisions.

PENALTIES

Under Code 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. Code 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 Code 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 1.6662-3(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. Code 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). Code section 6662(d)(1)(A) and (B).

Generally, 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. Code 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. 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 included 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). Moreover, a corporation must generally satisfy a standard higher than substantial authority to avoid a substantial understatement penalty in the case of a tax shelter. Code 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. Code 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 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. Code section 6664(d).

Although not anticipated by PDC, 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 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. Code section 6621. The rate of interest is adjusted monthly.

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. Code section 6698. 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 intends to 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.

SOCIAL SECURITY BENEFITS; SELF-EMPLOYMENT TAX

A General Partner's share of any income or loss attributable to his investment in Units will constitute "net earnings from self-employment" for either social security or self-employment tax purposes. The Social Security Act and the Code exclude from the definition of "net earnings from self-employment" a limited partner's distributive share of any item of income or loss from a partnership other than a guaranteed payment for personal services actually rendered. Therefore, a Limited Partner's share of income or loss attributable to his investment in Units will not constitute "net earnings from self-employment" for either social security or self-employment purposes.

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 Appendix D to the Prospectus and to all references to our firm in the Prospectus.

Sincerely,

/s/ Duane Morris LLP

DUANE MORRIS LLP

No dealer, salesman or other person has been authorized to give any information or make any representations other than those contained in this prospectus in connection with this offering. You should rely only upon the information contained in this prospectus. We have not authorized anyone to provide you with different information.

If it is against the law in any state to make an offer to sell the units (or to solicit an offer from someone to buy the units), then this prospectus does not apply to any person in that state, and no offer or solicitation is made by this prospectus to any person and we do not authorize the use of this prospectus to any person in that state.

Throughout this offering, all dealers effecting transactions in the registered securities, whether or not participating in this distribution, are required to deliver a prospectus. This is in addition to the obligation of dealers to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

20,000 Preformation Units of
General and Limited
Partnership Interest

[PDC logo]

PDC 2004-2006
DRILLING PROGRAM

$400,000,000
Aggregate Subscriptions

PROSPECTUS

July 18, 2005

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Dealer Manager

A Member of the National Association of Securities Dealers, Inc. and Securities Investor Protection Corporation