

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004

Commission File Number 000-50616

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities
Exchange Act of 1934 for the transaction period from ____ to ____

PDC 2003-B LIMITED PARTNERSHIP

(Exact name of registrant as specified in its charter)

West Virginia
(State or other jurisdiction of
incorporation or organization)

55-0825013
(I.R.S. Employer
Identification No.)

103 East Main Street, Bridgeport, West Virginia 26330
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code (304) 842-3597

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT: NONE

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

General and Limited Partnership Interests

(Title of class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes No X

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

Indicate by check mark whether the registrant is an accelerated filer (as definition in Rule 12b-2 of the Exchange Act). Yes No X

There is no trading market for the registrant's securities.

PART I

ITEM 1. BUSINESS.

General

PDC 2003-B Limited Partnership ("the Partnership") is a limited partnership formed on September 3, 2003 pursuant to the West Virginia Uniform Limited Partnership Act. Petroleum Development Corporation ("PDC") serves as Managing General Partner of the Partnership.

Since the commencement of operations on September 3, 2003, the Partnership has been engaged in onshore, domestic oil and natural gas exploration exclusively in the Rocky Mountain Region. A total of 19 limited partners contributed initial capital of \$395,869 and a total of 782 additional general partners contributed initial capital of \$16,950,032 and PDC (Managing General Partner) contributed \$3,772,733 in capital as a participant in accordance with contribution provisions of the Limited Partnership Agreement (the Agreement). During 2004 in accordance with the Partnership Agreement, all Additional General Partners were converted to Limited Partners.

Under the terms of the Agreement, the allocation of revenues is as follows:

	<u>Allocation of Revenues</u>
Additional General and Limited Partners	<u>80%</u>
Managing General Partner	<u>20%</u>

Operating and direct costs are allocated and charged to the additional general and limited partners and the Managing General Partner in the same percentages as revenues are allocated. Leasehold, drilling and completion costs, and equipment costs are borne 80% by the Additional General and Limited Partners and 20% by the Managing General Partner. See Footnote 4 of financial statements for a complete description of the allocation of Partnership revenue and costs.

Employees

The Partnership has no employees; however, PDC has approximately 120 employees, including 17 in finance and data processing, 8 in administration, 12 in exploration and development, 78 in production and 5 in natural gas marketing.

Plan of Operations

The Partnership participated in the drilling of 26 gross (23.2 net) wells and will continue to operate and produce its 26 gross productive wells. The Partnership does not have unexpended initial capital and no additional drilling activity is planned.

See Item 2 herein for information concerning the Partnership's gas wells.

Markets for Oil and Gas

The availability of a market for any oil and gas produced from the operations of the Partnership will depend upon a number of factors beyond the control of the Partnership which cannot be accurately predicted. These factors include the proximity of the Partnership wells to and the capacity of natural gas pipelines, the availability and price of competitive fuels, fluctuations in seasonal supply and demand, and government regulation of supply and demand created by its pricing and allocation restrictions. Oversupplies of gas can be expected to occur from time to time and may result in the Partnership's wells being shut-in or curtailed. Increased imports of oil and natural gas have occurred and are expected to continue. The effects of such imports could adversely impact the market for domestic oil and natural gas. All oil and natural gas is sold under contracts based on market sensitive indexes that vary from month to month. No fixed price contracts are in place. The Partnership sold oil and natural gas to several entities of which three customers accounted for 41.0%, 29.6% and 29.4% of the Partnership's total oil and natural gas sales for the period ended December 31, 2004 and 55.5%, 24.1% and 20.4% for the period from September 3, 2003 (date of inception) to December 31, 2003.

Derivatives and Hedging Activities

The Managing General Partner, through its subsidiary Riley Natural Gas, has been in the gas marketing business since 1986. During that time period, the Managing General Partner has utilized and continues to utilize commodity based derivative instruments as hedges to manage a portion of the Partnership's exposure to price volatility stemming from natural gas production. These instruments consist of NYMEX-traded natural gas futures and option contracts for eastern Colorado production, and CIG (Colorado Interstate Gas Index)-based contracts for other Colorado production and NYMEX traded oil futures and option contracts for Colorado oil production. The contracts hedge committed and anticipated natural gas sales, generally forecasted to occur within the next 2 year period. The Managing General Partner does not hold or issue derivatives for trading or speculative purposes and permits utilization of hedges only if there is an underlying physical position. See "Commodity Price Risk" under item 7A.

Notwithstanding the measure taken by the Managing General Partner to attempt to control price risk, the Partnership remains subject to price fluctuations for natural gas and oil sold in the spot market. The Managing General Partner continues to evaluate the potential for reducing these risks by entering into hedge transactions. In addition, the Managing General Partner may also close out any portion of hedges that may exist from time to time.

Competition

The Partnership competes in marketing its gas and oil with numerous companies and individuals, many of which have financial resources, staffs and facilities substantially greater than those of the Partnership or Petroleum Development Corporation.

State Regulations

State regulatory authorities have established rules and regulations requiring permits for well operations, reclamation bonds and reports concerning operations. States also have statutes and regulations concerning the spacing of wells, environmental matters and conservation, and have established regulations concerning the unitization and pooling of oil and gas properties and maximum rates of production from oil and gas wells. The Partnership believes it has complied in all material respects with applicable state regulations. The Partnership estimates it has spent approximately \$1,154 and \$116,000 in 2004 and 2003, respectively to comply with federal and state regulations.

Federal Regulations

Regulation of Liquid Hydrocarbons. Liquid hydrocarbons (including crude oil and natural gas liquids) were subject to federal price and allocation controls until January 1981 when controls were effectively eliminated by executive order of the President. As a result, to the extent the Partnership sells oil produced from its properties, those sales are at unregulated market prices.

Although it appears unlikely under present circumstances that controls will be reimposed upon liquid hydrocarbons, it is possible Congress may enact such legislation at a future date.

Natural Gas Regulation. Sale of natural gas by the Partnership is subject to regulation of production, transportation and pricing by governmental regulatory agencies. Generally, the regulatory agency in the state where a producing well is located regulates production activities and, in addition, the transportation of gas sold intrastate. The Federal Energy Regulatory Commission (FERC) regulates the operation and cost of interstate pipeline operators who transport gas. Currently the price of gas sold by the Partnership is not regulated by any state or federal agency.

Proposed Regulation. Numerous proposals concerning energy are being considered by the United States Congress, various state legislatures and regulatory agencies. The possible outcome and effect of these proposals cannot be accurately predicted.

Environmental and Safety Regulation. The Partnership believes that it complies, in all material respects, with all legislation and regulations affecting its operations in the drilling and production of oil and gas wells and the discharge of wastes. To date, compliance with such provisions and regulations has not had a material effect upon the Partnership's expenditures for capital equipment, its operations or its competitive position. The cost of such compliance is not anticipated to be material in the future.

ITEM 2. PROPERTIES.

Drilling Activity

The following table sets forth the results of the Partnership's drilling activity from September 3, 2003 (date of inception) to December 31, 2004. All of the Partnership's wells drilled and producing are located in Colorado.

Development Wells					
Gross Wells			Net Wells		
<u>Productive</u>	<u>Dry</u>	<u>Total</u>	<u>Productive</u>	<u>Dry</u>	<u>Total</u>
<u>26</u>	=	<u>26</u>	<u>23.2</u>	=	<u>23.2</u>

The Partnership has not participated in any exploratory wells. No additional drilling activity is planned.

Production

See "Management's Discussion and Analysis" on page 5 for Partnership production.

Reserves

See "Footnote 8" to the Partnership's financial statements for information related to the Partnership's oil and gas reserves.

Productive Wells

As outlined in the above table, the Partnership has a total of 26 gross productive wells (23.2 net wells) all of which are located in Colorado.

A "productive well" is a well producing, or capable of producing, oil and gas in commercial quantities. For purposes of the above table, a "gross well" is one in which the Partnership has a working interest and a "net well" is a gross well multiplied by the Partnership's working interest to which it is entitled under its drilling agreement.

Title to Properties

The Partnership's interests in producing acreage are in the form of assigned direct interests in leases. Such properties are subject to customary royalty interests generally contracted for in connection with the acquisition of properties and could be subject to liens incident to operating agreements, liens for current taxes and other burdens. The Partnership believes that none of these burdens materially interfere with the use of such properties in the operation of the Partnership's business.

As is customary in the oil and gas industry, little or no investigation of title is made at the time of acquisition of undeveloped properties (other than a preliminary review of local mineral records). Investigations are generally made, including in most cases receiving a title opinion of legal counsel, before commencement of drilling operations. A thorough examination of title has been made with respect to all of the Partnership's producing properties and the Partnership believes that it has generally satisfactory title to such properties.

ITEM 3. LEGAL PROCEEDINGS.

The Managing General partner as driller/operator is not party to any legal action that it believes would have a materially adverse affect on the Managing General Partner's or Partnership's business, financial condition, results of operations or liquidity.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

NON-APPLICABLE

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

At December 31, 2003, PDC 2003-B Limited Partnership had one Managing General Partner and a total of 19 Limited Partners who paid for 19.79 units at \$20,000 per unit of limited partnership interest, a total of 782 Additional General Partners who paid for 847.54 units at \$20,000 per unit of additional general partnership interests. No established public trading market exists for the interests.

Limited and additional general partnership interests are transferable, however no assignee of an interest in the Partnership can become a substituted partner without the written consent of the transferor and the Managing General Partner. There is no established trading market for the securities of the Partnership.

ITEM 6. SELECTED FINANCIAL DATA.

The selected financial data presented below has been derived from audited financial statements of the Partnership appearing elsewhere herein.

	Year Ended <u>December 31, 2004</u>	Period from September 3, 2003 (date of inception) to <u>December 31, 2003</u>
Oil and Gas Sales	\$6,213,210	1,185,222
Costs and Expenses	3,526,159	1,173,622
Net income	2,689,075	35,388
Allocation of Net income (loss):		
Managing General Partner	537,815	93,807
Limited and Additional General Partners	2,151,260	(58,419)
Per Limited and Additional General Partner Unit	2,480	(67)
Total Assets	17,017,034	19,360,688
Cash Distributions:		
Managing General Partner	1,021,705	-
Limited and Additional General Partners	4,086,828	-

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Liquidity and Capital Resources

The Partnership was funded on September 3, 2003 with initial Limited and Additional General Partner contributions of \$17,345,901 and the Managing General Partner's cash contribution of \$3,772,733 in accordance with the Agreement. After payment of syndication costs of \$1,821,320 and a one-time management fee to the Managing General Partner of \$433,648 the Partnership had available cash of \$18,863,666 for Partnership activities.

The Partnership began exploration and development activities subsequent to the funding of the Partnership and completed these activities by December 31, 2003. Twenty-six wells have been drilled, all of which have been completed as producers. No additional wells will be drilled.

The Partnership had working capital at December 31, 2004 of \$1,068,492.

Operations are expected to be conducted with available funds and revenues generated from oil and gas activities. No bank borrowings are anticipated.

Results of Operations

2004 Results Compared to 2003

Oil and gas sales for the year ended December 31, 2004 were \$6,213,210 compared to \$1,185,222 for the period from September 3, 2003 (date of inception) to December 31, 2003. For the year ended December 31, 2004, the Partnership sold 771,033 Mcf of gas and 66,031 barrels of oil at average sales prices of \$5.03 and \$35.38, respectively. This compared with 132,623 Mcf of gas and 22,654 barrels of oil sold at average sales prices of \$3.97 and \$29.06, respectively for the period from September 3, 2003 (date of inception) to December 31, 2003. Lifting cost per Mcfe in 2004 amounted to \$.80 as compared to \$0.65 for 2003. This increase is partially attributed to the increase in severance and property taxes and a full year of production in 2004. Depreciation, depletion and amortization increased from \$548,863 for the period from September 3, 2003 (date of inception) to December 31, 2003 to \$2,573,913 for the year ended December 31, 2004 as a result of higher volumes of natural gas and oil sold. Cash distributions to the partners amounted to \$5,108,533 in 2004.

2003 Results

Oil and gas production from the wells commenced during the fourth quarter of 2003 with revenue distributions to the partners commencing in the first quarter of 2004. For the period from September 3, 2003 (date of inception) to December 31, 2003, the Partnership sold 132,623 Mcf of gas and 22,654 barrels of oil at average sales prices of \$3.97 and \$29.06, respectively. Lifting cost per Mcfe in 2003 amounted to \$0.65. In accordance with the Partnership agreement, a one-time management fee equal to 2-1/2% of investors' subscriptions was charged to the Partnership in the amount of \$433,648 by the Managing General Partner. This fee was paid by the Partnership to the managing general partner of the Partnership upon funding the Partnership.

The Partnership's revenues from oil and natural gas sales will be affected by changes in prices. As a result of changes in federal regulations, gas prices are highly dependent on the balance between supply and demand. The Partnership's gas sales prices are subject to increase and decrease based on various market sensitive indices.

Critical Accounting Policies and Estimates

Certain accounting policies are very important to the portrayal of the Partnership's financial condition and results of operations and require management's most subjective or complex judgments. In applying those policies, our management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on our historical experience, our observance of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see "Note 1 - Summary of significant account policies" in our financial statements and related notes. The Partnership's critical accounting policies and estimates are as follows:

Revenue Recognition

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 Managing General Partner under contracts with terms ranging from one month to three years. Virtually all of the Managing General Partner'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 Partnership's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Managing General Partner believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Managing General Partner currently uses the "Net-Back" method of accounting for transportation arrangements of natural gas sales. The Managing General Partner 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 the Managing General Partner's 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 Partnership is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Partnership does not refine any of its oil production. The Partnership's crude oil production is sold to purchasers at or near the Partnership's wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

Accounting for Derivatives Contracts at Fair Value

The Partnership uses derivative instruments to manage its commodity and financial market risks. Accounting requirements for derivatives and hedging activities are complex; interpretation of these requirements by standard-setting bodies is ongoing.

Derivatives are reported on the Balance Sheet at fair value. Changes in fair value of derivatives that are not designated as accounting hedges are recorded in earnings.

The measurement of fair value is based on actively quoted market prices, if available. Otherwise, the Partnership seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based on valuation methodologies considered appropriate by the Partnership's management.

For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value. In addition, for hedges of forecasted transactions, the Partnership must estimate the expected future cash flows of the forecasted transactions, as well as evaluate the probability of the occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could affect the timing of recognition in earnings for changes in fair value of certain hedging derivatives.

Use of Estimates in Long-Lived Asset Impairment Testing

Impairment testing for long-lived assets and intangible assets with definite lives is required when circumstances indicate those assets may be impaired. In performing the impairment test, the Partnership would estimate the future cash flows associated with individual assets or groups of assets. Impairment must be recognized when the undiscounted estimated future cash flows are less than the related asset's carrying amount. In those circumstances, the asset must be written down to its fair value, which, in the absence of market price information, may be estimated as the present value of its expected future net cash flows, using an appropriate discount rate. Although cash flow estimates used by the Partnership are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Oil and Gas Properties

Exploration and development costs are accounted for by the successful efforts method.

The Partnership assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated 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 book value thereof, less proceeds or salvage value, is credited or charged to income. Upon sale of a partial unit of property, the proceeds are credited to accumulated depreciation and depletion.

ITEM 7A. Quantitative and Qualitative Disclosure About Market Risk.

Market-Sensitive Instruments and Risk Management

The Partnership's primary market risk exposure is commodity price risk. This exposure is discussed in detail below:

Commodity Price Risk

The Managing General Partner utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its oil and natural gas sales. These instruments consist of natural gas futures contracts and option contracts for CIG-based contracts traded by JP Morgan 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 Managing General Partner will receive for the volume to which the hedge relates. As a result, while these hedging arrangements are structured to reduce Partnership's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Partnership might otherwise have received from price changes associated with the hedged commodity. The Partnership'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 the Partnership as of December 31, 2004 and 2003.

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	Floors	207,739	3.94	-	40,914
Natural Gas	Ceilings	103,870	5.15	-	(77,495)
Oil	Floors	36,767	32.30	1,187,569	31,324

Oil	Ceilings	18,383	40.00	735,337	(99,438)
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Contracts maturing in 12 months following December 31, 2004

Natural Gas	Floors	207,739	3.94	-	40,914
Natural Gas	Ceilings	103,870	5.15	-	(77,495)
Oil	Floors	36,767	32.30	1,187,569	31,324
Oil	Ceiling	18,383	40.00	735,337	(99,438)

Prior Year Total Contracts as of December 31, 2003

Natural Gas	Purchase	-	-	-	-
Natural Gas	Floors	-	-	-	-
Natural Gas	Ceilings	-	-	-	-

The maximum term over which the Partnership is hedging exposure to the variability of cash flows for commodity price risk is 12 months.

The average NYMEX closing price for natural gas for the years 2004 and 2003 was \$6.14 per Mmbtu and \$5.39 per Mmbtu. The average NYMEX closing price for oil for the years 2004 and 2003 was \$41.44 per bbl and \$30.98 per bbl. The average CIG closing price for natural gas for the years 2004 and 2003 was \$5.17 per Mmbtu and \$4.04 per Mmbtu. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulations and new drilling activities within the industry.

Disclosure of Limitations

As the information above incorporates only those exposures that exist at December 31, 2004, it does not consider those exposures or positions which could arise after that date. As a result, the Partnership's ultimate realized gain or loss with respect to commodity price fluctuations will depend on the exposures that arise during the period, the Partnership's hedging strategies at the time and commodity prices at the time.

PART III

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA:

The response to this Item is set forth herein in a separate section of this Report, beginning on Page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

NONE.

ITEM 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of the Managing General Partner's management, including the Managing General Partner's Chief Executive Officer and Chief Financial Officer, the Managing General Partner has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Exchange Act Rule 13a-14(c)) as of the end of the period covered by this annual report on Form 10-K, and, based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective in all material respects, including those to ensure that information required to be disclosed in reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in the Commission's rules and forms, and is accumulated and communicated to management, including the Managing General Partner's Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely disclosure. There have been no significant changes in our internal controls or in other factors that could significantly affect these controls in the fourth quarter and subsequent to the date of their evaluation.

ITEM 9B. OTHER INFORMATION

NONE

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The Partnership has no directors or executive officers. The partnership is managed by Petroleum Development Corporation (the Managing General Partner). Petroleum Development Corporation's common stock is traded in the NASDAQ National Market and Form 10-K for 2004 has been filed with the Securities and Exchange Commission.

Although the Partnership has no Code of Ethics, Petroleum Development Corporation, the Managing General Partner of the Partnership, has a Code of Ethics that applies to its senior executive officers. The Code of Ethics is posted on the website of Petroleum Development Corporation at www.petd.com.

ITEM 11. EXECUTIVE COMPENSATION.

NON-APPLICABLE.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS, MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

NON-APPLICABLE.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Pursuant to the authorization contained in the Limited Partnership Agreement, PDC receives fees for services rendered and reimbursement of certain expenses from the Partnership. See respective drilling prospectus for further information regarding the Limited Partnership Agreement. The following table presents compensation or reimbursements by the Partnership to PDC or other related parties for the year ended December 31, 2004 and the period from September 3, 2003 (date of inception) to December 31, 2003.

	Year Ended December 31, 2004	Period from September 3, 2003 (date of inception) to December 31, 2003
Drilling and completion costs	-	18,863,666
Lifting costs	935,064	173,746
Syndication cost *	-	1,821,320
Management fee	-	433,648
Tax return preparation	3,960	4,970
Direct administrative cost	1,999	3,275

* Consists of broker dealer commission paid to PDC Securities Incorporated (100% subsidiary of the Managing General Partner and Dealer Manager of the drilling program) which was reallocated or paid to the Soliciting Broker Dealers of the drilling program.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the year ended December 31, 2004 and the period from September 3 (date of inception) to December 31, 2003, the partnership paid KPMG LLP \$4,881 and \$4,320, respectively, for professional services for the audit of the Partnership's financial statements in its Form 10-K and review of financial statements included in the Partnership's Form 10-Qs. Included in the period from September 3, 2003 (date of inception) to December 31, 2003 was \$1,000 for income tax services provided by KPMG LLP.

Pre-Approval Policies and Procedures

The Sarbanes-Oxley Act of 2002 requires that all services provided to the Partnership by its independent accountants be subject to pre-approval by the Audit Committee or authorized members of the Committee. Since

the Partnership does not have an Audit Committee, the Managing General Partner's Audit Committee also serves for the Partnership. The Audit Committee has adopted policies and procedures for pre-approval of all audit services and non-audit services to be provided by the Partnership's independent accountants. Services necessary to conduct the annual audit must be pre-approved by the Audit Committee or by the authorized Audit Committee member.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(1) Financial Statements

See Index to Financial Statements on F-2

(2) Financial Statement Schedules

See Index to Financial Statements on page F-2. All financial statement schedules are omitted because they are not required, inapplicable, or the information is included in the Financial Statements or Notes thereto.

(3) Exhibits

- 4.1 Form of Limited Partnership Agreement (incorporated by reference to Appendix A to Form S-1, SEC File No. 333-47622, and Rule 424 final prospectus, dated May 22, 2003, of PDC 2003 Drilling Program, filed with the SEC on May 23, 2003).
- 14 Code of Ethics of Petroleum Development Corporation (incorporated by reference to the posted code on the web site of Petroleum Development Corporation at www.petd.com).
- 31.1 Rule 13a-14(a)/15d-14(c) Certification of Chief Executive Officer of Petroleum Development Corporation, the managing general partner of the Limited Partnership.
- 31.2 Rule 13a-14(a)/15d-14(c) Certification of Chief Financial Officer of Petroleum Development Corporation, the managing general partner of the Limited Partnership.
- 32.1 Title 18 U.S.C. Section 1350 (Section 906 of Sarbanes-Oxley Act of 2002) Certifications by Chief Executive Officer and Chief Financial Officer of Petroleum Development Corporation, the managing general partner of the Limited Partnership.

CONFORMED COPY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PDC 2003-B Limited Partnership
By its Managing General Partner
Petroleum Development Corporation

By /s/ Steven R. Williams
Steven R. Williams, Chairman
April 19, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

Signature	Title	Date
<u>/s/ Steven R. Williams</u> Steven R. Williams	Chairman, Chief Executive Officer and Director	April 19, 2005
<u>/s/ Darwin L. Stump</u> Darwin L. Stump	Chief Financial Officer and Treasurer (principal financial and accounting officer)	April 19, 2005
<u>/s/ Thomas E. Riley</u> Thomas E. Riley	President and Director	April 19, 2005
<u>/s/ Donald B. Nestor</u> Donald B. Nestor	Director	April 19, 2005
<u>/s/ Vincent F. D'Annunzio</u> Vincent F. D'Annunzio	Director	April 19, 2005

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Financial Statements for Annual Report
on Form 10-K to Securities and Exchange
Commission

Year ended December 31, 2004 and
Period from September 3, 2003 (Date of Inception)
to December 31, 2003

(With Independent Registered Public Accounting Firm's Report Thereon)

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

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All financial statement schedules have been omitted because they are not applicable or not required or the required information is shown in the financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Partners

PDC 2003-B Limited Partnership:

We have audited the accompanying balance sheets of PDC 2003-B Limited Partnership (a West Virginia limited partnership) as of December 31, 2004 and 2003, and the related statements of operations, partners' equity and comprehensive income (loss), and cash flows for the year ended December 31, 2004 and period from September 3, 2003 (date of inception) to December 31, 2003. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements 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 financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of PDC 2003-B Limited Partnership as of December 31, 2004 and 2003, and the results of its operations and its cash flows for the year ended December 31, 2004 and the period from September 3, 2003 (date of inception) to December 31, 2003, in conformity with U.S. generally accepted accounting principles.

KPMG LLP

Pittsburgh, Pennsylvania
April 19, 2005

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Balance Sheets

December 31, 2004 and 2003

Assets

	<u>2004</u>	<u>2003</u>
Current assets:		
Cash	\$20,399	23,773
Accounts receivable - oil and gas revenues	<u>1,244,771</u>	<u>1,011,476</u>
Total current assets	1,265,170	1,035,249
 Oil and gas properties, successful efforts method (notes 3 and 6):	 18,874,640	 18,874,302
Less accumulated depreciation, depletion and amortization	<u>3,122,776</u>	<u>548,863</u>
	<u>15,751,864</u>	<u>18,325,439</u>
	<u>\$17,017,034</u>	<u>19,360,688</u>

Liabilities and Partners' Equity

Current liabilities:		
Accrued expenses	<u>\$196,678</u>	<u>17,190</u>
Total current liabilities	196,678	17,190
 Asset retirement obligation	 11,807	 10,796
 Partners' equity	 <u>16,808,549</u>	 <u>19,332,702</u>
	<u>\$17,017,034</u>	<u>\$19,360,688</u>

See accompanying notes to financial statements.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Operations
Year Ended December 31, 2004 and
Period from September 3, 2003 (Date of Inception) to December 31, 2003

	<u>2004</u>	<u>2003</u>
Revenues:		
Sales of oil and gas	\$6,213,210	1,185,222
Interest income	<u>2,024</u>	<u>23,788</u>
	6,215,234	1,209,010
Expenses (note 3):		
Management fee	-	433,648
Lifting costs	935,064	173,746
Independent engineering fee	5,669	3,800
Independent audit fee	4,881	4,320
Tax return preparation	3,960	5,970
Direct administrative cost	2,672	3,275
Depreciation, depletion and amortization	<u>2,573,913</u>	<u>548,863</u>
	<u>3,526,159</u>	<u>1,173,622</u>
Net income	<u>\$2,689,075</u>	<u>35,388</u>
Net income (loss) per limited and additional general partner unit	<u>\$2,480</u>	<u>(67)</u>

See accompanying notes to financial statements.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Partners' Equity and Comprehensive Income (Loss)
Year ended December 31, 2004 and
Period from September 3, 2003 (Date of Inception) to December 31, 2003

	Limited and Additional General <u>Partners</u>	Managing General <u>Partner</u>	Accumulated Other Comprehensive <u>Income (Loss)</u>	<u>Total</u>
Partners' initial capital contributions	\$17,345,901	3,772,733	-	21,118,634
Syndication costs	(1,821,320)	-		(1,821,320)
Comprehensive income (loss):				
Net income (loss)	(58,419)	93,807		35,388
Change in fair value of outstanding hedging positions			-	
Reclassification adjustment for settled contracts included in net income (loss)			<u>-</u>	
Other comprehensive income (loss)			-	<u>-</u>
Comprehensive income (loss)	<u> </u>	<u> </u>	<u> </u>	<u>35,388</u>
Balance December 31, 2003	15,466,162	3,866,540	-	19,332,702
Distribution to partners	(4,086,828)	(1,021,705)		(5,108,533)
Comprehensive income (loss):				
Net income	2,151,260	537,815		2,689,075
Change in fair value of outstanding hedging positions			(187,271)	
Reclassification adjustment for settled contracts included in net income (loss)			<u>82,576</u>	
Other comprehensive income (loss)			(104,695)	<u>(104,695)</u>
Comprehensive income (loss)	<u> </u>	<u> </u>	<u> </u>	<u>2,584,380</u>
Balance December 31, 2004	<u>\$13,530,594</u>	<u>3,382,650</u>	<u>(104,695)</u>	<u>16,808,549</u>

See accompanying notes to financial statements.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Cash Flows
Year Ended December 31, 2004 and
Period from September 3, 2003 (Date of Inception) to December 31, 2003

	<u>2004</u>	<u>2003</u>
Cash flows from operating activities:		
Net income	\$2,689,075	35,388
Adjustments to reconcile net income to net cash used by operating activities:		
Depreciation, depletion and amortization	2,573,913	548,863
Accretion of asset retirement obligation	673	160
Changes in operating assets and liabilities:		
Increase in accounts receivable -oil and gas revenues	(161,057)	(1,011,476)
Increase in accrued expenses	<u>2,555</u>	<u>17,190</u>
Net cash provided from (used by) operating activities	<u>5,105,159</u>	<u>(409,875)</u>
Cash flows from investing activities:		
Expenditures for oil and gas properties	<u>-</u>	<u>(18,863,666)</u>
Net cash used by investing activities	<u>-</u>	<u>(18,863,666)</u>
Cash flows from financing activities:		
Limited and additional general partner contributions	-	17,345,901
Managing General Partner contribution	-	3,772,733
Syndication cost paid	-	(1,821,320)
Distributions to partners	<u>5,108,533</u>	<u>-</u>
Net cash (used by) provided from financing activities	<u>(5,108,533)</u>	<u>19,297,314</u>
Net (decrease) increase in cash	(3,374)	23,773
Cash at beginning of period	<u>23,773</u>	<u>-</u>
Cash at end of period	<u>\$20,399</u>	<u>23,773</u>

See accompanying notes to financial statements.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

December 31, 2004 and 2003

(1) Summary of Significant Accounting Policies

Partnership Financial Statement Presentation Basis

The financial statements include only those assets, liabilities and results of operations of the partners which relate to the business of PDC 2003-B Limited Partnership (the Partnership). The statements do not include any assets, liabilities, revenues or expenses attributable to any of the partners' other activities. Petroleum Development Corporation ("PDC") serves as the Managing General Partner of the Partnership.

Oil and Gas Properties

The Partnership follows the successful efforts method of accounting for the cost of exploring for and developing oil and gas reserves. Under this method, costs of development wells, including equipment and intangible drilling costs related to both producing wells and developmental dry holes, and successful exploratory wells are capitalized and amortized on an annual basis to operations by the units-of-production method using estimated proved developed reserves determined at December 31, 2004 and 2003 by the an independent petroleum engineer, Wright & Company, Inc. If a determination is made that an exploratory well has not discovered economically producible reserves, then its costs are expensed as dry hole costs.

The Partnership assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future 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.

Revenue Recognition

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 Managing General Partner under contracts with terms ranging from one month to three years. Virtually all of the Managing General Partner'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 Partnership's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Managing General Partner believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Managing General Partner currently uses the "Net-Back" method of accounting for transportation arrangements of natural gas sales. The Managing General Partner 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 the Managing General Partner's customers and reflected in the wellhead price.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

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 Partnership is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Partnership does not refine any of its oil production. The Partnership's crude oil production is sold to purchasers at or near the Partnership's wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

The Partnership sold oil and natural gas to several entities of which three customers accounted for 41.0%, 29.6% and 29.4% of the Partnership's total oil and natural gas sales for the period ended December 31, 2004 and 55.5%, 24.1% and 20.4% for the period from September 3, 2003 (date of inception) to December 31, 2003.

Income Taxes

Since the taxable income or loss of the Partnership is reported in the separate tax returns of the partners, no provision has been made for income taxes on the Partnership's books.

Under federal income tax laws, regulations and administrative rulings, certain types of transactions may be accorded varying interpretations. Accordingly, the Partnership's tax return and, consequently, individual tax returns of the partners may be changed to conform to the tax treatment resulting from a review by the Internal Revenue Service.

Derivative Financial Instruments

The Managing General Partner utilizes commodity based derivative instruments as hedges to manage a portion of the Partnership's exposure to price volatility stemming from natural gas production. These instruments consist of costless collars and option contracts traded on the CIG (Colorado Interstate Gas Index). The costless collars and option contracts hedge committed and anticipated natural gas sales generally forecasted to occur within a 24 month period. The Partnership does not hold or issue derivatives for trading or speculative purposes.

All derivatives are recognized on the Partnership balance sheet at their fair value. On the date the derivative contract is entered into, the Managing General Partner 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 Managing General Partner 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 Managing General Partner 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 Partnership 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 accumulated other comprehensive income (loss), 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 Partnership 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

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

the derivative is designated as a hedging instrument, because it is probable that a forecasted transaction will not occur, or the Partnership determines that designation of the derivative as a hedging instrument is no longer appropriate, hedge accounting will be discontinued.

By using derivative financial instruments to hedge exposures to changes in commodity prices, the Managing General Partner exposes the Partnership to credit 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 Partnership, which creates credit risk. The Managing General Partner minimizes the credit risk in derivative instruments by entering into transactions with high-quality counterparties.

Use of Estimates

The Partnership 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 financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties which are used in assessing impairment of long-lived assets.

(2) Organization

The Partnership was organized as a limited partnership on September 3, 2003, in accordance with the laws of the State of West Virginia for the purpose of engaging in the drilling, completion and operation of oil and gas development and exploratory wells in the Rocky Mountain Region.

Purchasers of partnership units subscribed to and fully paid for 19.79 units of limited partner interest and 847.54 units of additional general partner interests at \$20,000 per unit (Investor Partners). Petroleum Development Corporation has been designated the Managing General Partner of the Partnership. Although costs, revenues and cash distributions allocable to the limited and additional general partners are shared pro rata based upon the amount of their subscriptions, including the Managing General Partner to the extent of its capital contributions, there are significant differences in the federal income tax effects and liability associated with these different types of units in the Partnership.

Upon completion of the drilling phase of the Partnership's wells, all additional general partners units are converted into units of limited partner interests and thereafter become limited partners of the Partnership. Limited partners do not have any rights to convert their units into units of additional general partner interests in the Partnership.

In accordance with the terms of the Partnership Agreement (the Agreement), the Managing General Partner manages all activities of the Partnership and acts as the intermediary for substantially all Partnership transactions.

(3) Transactions with Managing General Partner and Affiliates

Pursuant to the authorization contained in the Limited Partnership Agreement, PDC receives fees for services rendered and reimbursement of certain expenses from the Partnership. See respective drilling prospectus for further information regarding the Limited Partnership Agreement. The following table presents compensation or reimbursements by the Partnership to PDC or other related parties for the year ended December 31, 2004 and the period from September 3, 2003 (date of inception) to December 31, 2003.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

	Year Ended December 31, 2004	Period from September 3, 2003 (date of inception) to December 31, 2003
Drilling and completion costs	\$ -	18,863,666
Lifting costs	935,064	173,746
Syndication cost *	-	1,821,320
Management fee	-	433,648
Tax return preparation	3,960	4,970
Direct administrative cost	1,999	3,275

* Consists of broker dealer commission paid to PDC Securities Incorporated (100% subsidiary of the Managing General Partner and Dealer Manager of the drilling program) which was reallocated or paid to the Soliciting Broker Dealers of the drilling program.

(4) Allocation

The table below summarizes the participation of the Managing General Partner and the Investor Partners, taking account of the Managing General Partner's capital contribution equal to a minimum of 20% of the initial capital, in the costs and revenues of the Partnership.

	Investor Partners(5)(6)	Managing General Partner (5)(6)
<u>Partnership Costs</u>		
Broker-dealer Commissions and Expenses(1)	100%	0%
Management Fee(2)	100%	0%
Lease Costs	0%	100%
Tangible Well Costs	0%	100%
Intangible Drilling and Development Costs	100%	0%
Total Drilling and Completion Costs	80%	20%
Operating Costs(3)	80%	20%
Direct Costs(4)	80%	20%
Administrative Costs	0%	100%
<u>Partnership Revenues</u>		
Sale of Oil and Gas Production	80%	20%
Sale of Productive Properties	80%	20%
Sale of Equipment	0%	100%
Sale of Undeveloped Leases .	80%	20%
Interest Income	80%	20%

-
- (1) Organization and offering costs, net of the dealer manager commissions, discounts, due diligence expenses, and wholesaling fees of the Partnership were paid by the Managing General Partner and not from Partnership funds. In addition, organization and offering costs in excess of 10-1/2% of Subscriptions were paid by the Managing General Partner, without recourse to the Partnership.
- (2) Represents a one-time fee paid to the Managing General Partner on the day the Partnership is funded equal to 2-1/2% of total investor subscriptions.
- (3) Represents Operating costs incurred after the completion of productive wells, including monthly per-well charges paid to the Managing General Partner.

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

- (4) The Managing General Partner receives monthly reimbursement from the Partnership for its direct costs incurred by the Managing General Partner on behalf of the Partnership.
- (5) To the extent that Investor Partners receive preferred cash distributions, the allocations for Investor Partners will be increased accordingly and the allocation for the Managing General Partner will likewise be decreased.
- (6) The allocation of profits, losses and cash distributions of the Managing General Partner might be increased, and the allocation of profits, losses, and cash distributions of the Investor Partners might be decreased in the event that the Managing General Partner were to invest more than the Managing General Partner's minimum required Capital Contribution to cover tangible equipment and lease costs. The Managing General Partner will pay for the Partnership's share of all Leases and tangible well equipment. The entire Capital Contribution of the Investor Partners, after payment of brokerage commissions, due diligence reimbursement, and the Management Fee, was utilized to pay for intangible drilling costs. In the event that the Intangible Drilling Costs exceed the funds of the Investor Partners available for payment of Intangible Drilling Costs (herein "excess IDC"), a portion of the Capital Contribution of the Managing General Partner may be used to pay such excess IDC. If the cost of Leases and tangible well equipment were to exceed the Managing General Partner's Capital Contribution of 21-3/4% of the aggregate Capital Contribution of the Investor Partners, then the Managing General Partner will increase its Capital Contribution to fund such additional capital requirements and the Managing General Partner's allocation of profits, losses, and cash distributions will be increased to equal the percentage arrived at by dividing the Capital Contribution made by the Managing General Partner by the Capital Available for Investment; the allocation of the Investor Partners will be decreased accordingly.
- (7) In accordance with the repurchase provision of the partnership prospectus, PDC may repurchase units from the investor partners, which is entirely voluntary on the part of the partners. During 2004 and 2003 there were no units purchased by PDC.

(5) Derivative Financial Instruments

The Managing General Partner utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its oil and natural gas sales. These instruments consist of natural gas futures contracts and option contracts for CIG-based contracts traded by JP Morgan 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 Managing General Partner will receive for the volume to which the hedge relates. As a result, while these hedging arrangements are structured to reduce Partnership's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Partnership might otherwise have received from price changes associated with the hedged commodity. The Partnership'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 the Partnership as of December 31, 2004 and 2003.

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	Floors	207,739	3.94	-	40,914
Natural Gas	Ceilings	103,870	5.15	-	(77,495)
Oil	Floors	36,767	32.30	1,187,569	31,324
Oil	Ceilings	18,383	40.00	735,337	(99,438)

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PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

Contracts maturing in 12 months following December 31, 2004

Natural Gas	Floors	207,739	3.94	-	40,914
Natural Gas	Ceilings	103,870	5.15	-	(77,495)
Oil	Floors	36,767	32.30	1,187,569	31,324
Oil	Ceiling	18,383	40.00	735,337	(99,438)

Prior Year Total Contracts as of December 31, 2003

Natural Gas	Purchase	-	-	-	-
Natural Gas	Floors	-	-	-	-
Natural Gas	Ceilings	-	-	-	-

The maximum term over which the Partnership is hedging exposure to the variability of cash flows for commodity price risk is 12 months.

(6) Costs Relating to Oil and Gas Activities

The Partnership is engaged solely in oil and gas activities, all of which are located in the continental United States. Information regarding aggregate capitalized costs and results of operations for these activities is located in the basic financial statements. Costs capitalized for these activities are as follows:

	<u>December 31, 2004</u>	<u>December 31, 2003</u>
Lease acquisitions at cost	\$472,706	472,706
Intangible development costs	15,090,933	15,090,933
Well equipment	3,300,027	3,300,027
Capitalized asset retirement cost	<u>10,974</u>	<u>10,636</u>
	<u>\$18,874,640</u>	<u>18,874,302</u>

The following costs were incurred for the Partnership's oil and gas activities:

	Year Ended <u>December 31, 2004</u>	Period from September 3, 2003 (date of inception) to <u>December 31, 2003</u>
Costs incurred:		
Property acquisition costs	\$ -	472,706
Development costs	<u>-</u>	<u>18,390,960</u>
	<u>\$ -</u>	<u>18,863,666</u>

(7) Income Taxes

As a result of the differences in the treatment of certain items for income tax purposes as opposed to financial reporting purposes, primarily depreciation, depletion and amortization of oil and gas properties and the recognition of intangible drilling costs as an expense or capital item, the income tax basis of oil and gas properties differs from the basis used for financial reporting purposes. At December 31, 2004 and 2003 the income tax basis of the Partnership's oil and gas properties was \$1,623,726 and \$2,309,616.

(8) Supplemental Reserve Information (Unaudited)

Proved oil and gas reserves of the Partnership have been estimated at December 31, 2004 and 2003 by an independent petroleum engineer, Wright & Company, Inc. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. A copy of the reserve report has been made available to all partners. All of the partnership's reserves are proved developed. An analysis of the change in estimated quantities of proved developed oil and gas reserves is shown below:

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

	Oil (Bbls)	
	<u>2004</u>	<u>2003</u>
Proved developed reserves:		
Beginning of year	427,000	-
Revisions of previous estimates	(4,000)	-
New Discoveries and extensions		
Rocky Mountain Region	-	450,000
Production	<u>(66,000)</u>	<u>(23,000)</u>
End of year	<u>357,000</u>	<u>427,000</u>

	Gas (Mcfs)	
	<u>2004</u>	<u>2003</u>
Proved developed reserves:		
Beginning of year	7,270,000	-
Revisions of previous estimates	(694,000)	-
New Discoveries and extensions		
Rocky Mountain Region	-	7,403,000
Production	<u>(771,000)</u>	<u>(133,000)</u>
End of year	<u>5,805,000</u>	<u>7,270,000</u>

(9) 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 Partnership 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 Partnership 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.

	As of December 31,	
	<u>2004</u>	<u>2003</u>
Future estimated revenues	\$49,760,000	52,733,000
Future estimated production costs	(11,428,000)	(10,618,000)
Future estimated development costs	<u>(1,770,000)</u>	<u>(1,770,000)</u>
Future net cash flows	36,562,000	40,345,000
10% annual discount for estimated timing of cash flows	<u>(18,881,000)</u>	<u>(19,823,000)</u>
Standardized measure of discounted future estimated net cash flows	<u>\$17,681,000</u>	<u>20,522,000</u>

PDC 2003-B LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Notes to Financial Statements

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year Ended December 31, 2004	Period from September 3, 2003 (date of inception) to December 31, 2003
Sales of oil and gas production, net of production costs	\$(5,278,000)	(1,011,000)
Net changes in prices and production costs	4,452,000	-
Extensions, discoveries, and improved recovery, less related cost	-	41,356,000
Revisions of previous quantity estimates	(2,957,000)	-
Accretion of discount	942,000	-
Less: Discount at 10%	<u>-</u>	<u>(19,823,000)</u>
	<u><u>\$(2,841,000)</u></u>	<u><u>20,522,000</u></u>

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.