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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

[X]ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2003

Commission File Number 001-31264

[]Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transaction period from ___ to _____

PDC 2001-C LIMITED PARTNERSHIP
(Exact name of registrant as specified in its charter)

West Virginia	02-0533219
(State or other jurisdiction of incorporation or organization)	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 f or the past 90 days. Yes X No _

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 2001-C Limited Partnership ("the Partnership") is a limited partnership formed on November 9, 2001 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 November 9, 2001, the Partnership has been engaged in onshore, domestic oil and natural gas exploration exclusively in the Rocky Mountain Region. A total of 9 limited partners contributed initial capital of $430,000; a total of 586 additional general partners contributed initial capital of $10,197,234; and PDC (Managing General Partner) contributed $2,311,423 in capital as a participant in accordance with contribution provisions of the Limited Partnership Agreement (the Agreement). During 2002 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:

	Allocation of Revenues
Additional General and Limited Partners	80%
Managing General Partner	20%

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 110 employees which include a staff of geologists, petroleum engineers, landmen and accounting personnel who administer all of the Partnership's operations.

Plan of Operations

The Partnership participated in the drilling of nineteen gross (16.43 net) wells(all of which are productive) and will continue to operate and produce its nineteen 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 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 two customers accounted for 66.7% and 28.3% of the Partnership's total oil and natural gas sales for the year ended December 31, 2003 and 43.4% and 43.5% in 2002, respectively.

Hedging Activities

The Managing General Partner, through its subsidiary Riley Natural Gas (RNG), utilizes commodity-based derivative instruments as hedges to manage a portion of the Partnership's exposure to price volatility stemming from its natural gas sales and marketing activities. These instruments consist of CIG (Colorado Interstate Gas Index)-based contracts for Colorado production. The contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within the next twenty-four-month period. The Managing General Partner does not hold natural gas futures or options for speculative purposes and permits utilization of hedges only if there is an underlying physical position.

The Managing General Partner has extensive experience with the use of financial hedges to reduce the risk and impact of natural gas price changes. These hedges are used to "lock in" fixed prices from time to time for the Partnership's share of production, and to establish "floors" and "ceilings" or "collars" on the possible range of the price realized for the sale of natural gas and oil. In order for contracts to serve as effective hedges, there must be sufficient correlation to the underlying hedged transaction. While hedging can help provide price protection if spot prices drop, hedges can also limit upside potential.

For unhedged natural gas sales not subject to fixed price contracts, the Partnership is subject to price fluctuations for natural gas sold in the spot market. The Managing General Partner continues to evaluate the potential for reducing these risks by entering into hedge transactions. There are no hedge contracts outstanding as of December 31, 2003 related to oil production, however subsequent to year-end the Managing General Partner did enter into oil hedge contracts for 2004. See "Commodity Price Risk" under Item 7A.

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 $6,700 and $5,800 in 2003 and 2002, 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 to be 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 November 9, 2001 (date of inception) to December 31, 2003. All of the Partnership's wells drilled and producing are located in Colorado.

Development Wells					
Gross Wells			Net Wells		
Productive	Dry	Total	Productive	Dry	Total
18	-	18	15.53	-	15.53

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

Production

See "Management's Discussion and Analysis" on page 6 for Partnership production.

Reserves

See "Footnote 7" to the Partnership's financial statements for the Partnership's oil and gas reserves.

Productive Wells

As outlined in the above table, the Partnership has a total of 18 gross productive wells (15.53 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 would materially affect the Managing General Partner's or Partnership's operations or financial statements.

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

During 2003 the Managing General Partner proposed an amendment to Article 8.02 of the partnership agreement to delete the word "independent" from "independent petroleum engineers". The proposed amendment was submitted to a vote and was passed.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND SECURITY HOLDER MATTERS.

At December 31, 2001, PDC 2001-C Limited Partnership had one Managing General Partner, 9 Limited Partners who fully paid for 21.5 units at $20,000 per unit of limited partnership interests and a total of 586 Additional General Partners who fully paid for 509.8617 units at $20,000 per unit of additional general partnership interests. During 2002 in accordance with the Partnership Agreement, all Additional General Partners were converted to Limited Partners. At December 31, 2003, the Partnership had one Managing General Partner and 595 limited partners who paid for 531.3617 units at $20,000 per unit. 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.

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 December 31, 2003	Year Ended December 31, 2002	Period from November 9, 2001 (date of inception)to December 31, 2001
Oil and Gas Sales	$2,104,889	$1,741,435	-
Costs and Expenses	1,468,291	1,591,433	277,941
Cumulative Effect of change in accounting principle	(829)	-	-
Net Income(loss)	636,762	150,668	(271,143)
Allocation of Net Income(loss):			
Managing General Partner	127,352	30,134	(1,092)
Limited and Additional General Partners	509,410	120,534	(270,051)
Per Limited and Additional General Partner Unit	960	227	(508)
Total Assets	9,865,494	10,849,189	11,563,904
Cash Distributions			
Managing General Partner	325,021	213,837	-
Limited and Additional General Partners	1,300,092	855,354	-

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

Liquidity and Capital Resources

The Partnership was funded on November 9, 2001 with initial Limited and Additional General Partner contributions of $10,627,234 and the Managing General Partner's cash contribution of $2,311,423 in accordance with the Agreement. After payment of syndication costs of $1,115,860 and a one-time management fee to the managing general partner of $265,681 the Partnership had available cash of $11,557,116 for Partnership activities. During 2002 the Managing General Partner made an additional capital contribution in the amount of $199,371 which was expended for the development of oil and gas properties.

The Partnership had net working capital at December 31, 2003 of $257,759.

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

2003 Results Compared to 2002

Oil and gas sales for the year ended December 31, 2003 were $2,104,889 compared to $1,741,435 for the year ended December 31, 2002. For the year ended December 31, 2003, the Partnership sold 395,773 Mcf of gas and 21,635 barrels of oil at average sales prices of $3.66 and $30.40, respectively. This compared with 442,568 Mcf of gas and 33,875 barrels of oil sold at average sales prices of $2.01 and $25.09, respectively for the year ended December 31, 2002. Lifting cost per Mcfe in 2003 amounted to $1.00 as compared to $0.52 for 2002. This increase is partially attributed to the increase in severance and property taxes. The fixed costs of operations and well maintenance are allocated to lower production volumes, therefore increasing the lifting cost per Mcfe. Depreciation, depletion and amortization decreased from $1,242,841 for the year ended December 31, 2002 to $926,200 for the year ended December 31, 2003 as a result of lower volumes of natural gas and oil sold. Cash distributions to the partners amounted to $1,625,113 in 2003.

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.

2002 Results

Oil and natural gas sales commenced during the first quarter of 2002, with cash distributions to the partners commencing during the second quarter. For the year ended December 31, 2002, the Partnership sold 442,568 Mcf of gas and 33,875 barrels of oil at average sales prices of $2.01 and $25.09, respectively. Lifting cost per Mcfe in 2002 amounted to $0.52. Although the Partnership experienced a net income of only $150,668, depreciation, depletion and amortization is a non-cash expense and the Partnership distributed $1,069,191 to the Partners during 2002.

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 oil and natural gas are recognized when the right and responsibilities of ownership passes to the purchasers and are net of royalties.

Accounting for Derivative 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 Sheets 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.

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 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 flow, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

New Accounting Standards

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Partnership adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $7,169 and a related liability of $7,998 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $829.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS no. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights (leases) associated with extracting oil and gas intangible assets in the balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Partnership has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Partnership would be required to reclassify the historical cost of approximately $416,050 of mineral rights associated with developed oil and gas properties as of December 31, 2003 and 2002 out of oil and gas properties and into a separate intangible mineral rights assets line item. The Partnership's total balance sheet, cash flows and results of operations would not be affected since such intangible assets would continue to be amortized and assessed for impairment.

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

Natural gas and oil prices have been unusually volatile for the past few years, and the Partnership anticipates continued volatility in the future. Currently, the NYMEX futures reflect a market expectation of gas prices at Henry Hub close to or above record prices per million Btu's (Mmbtu). These prices look strong for 2004 although natural gas storage levels are near normal levels following a period where storage had been at a five-year low. The Partnership believes this situation creates the possibility of both periods of low prices and continued high prices.

Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas and oil markets has remained prevalent in the last few years and can have a material impact on our financial results. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003, Colorado prices began to increase, although they continue to trail prices in other areas. The Partnership believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Partnership believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity situation. The Partnership has commodity price hedging contracts for natural gas production from January 2004 through October 2004 to protect against possible short-term price weaknesses.

Because of the uncertainty surrounding gas prices the Managing General Partner used hedging agreements to manage some of the impact of fluctuations in prices for the Managing General Partner and its various limited partnership's share of production. Through October of 2004 the Partnership has in place a series of costless collars and option contracts. Under the collar arrangements, if the applicable index rises above the ceiling price, the Partnership pays the counterparty, however if the index drops below the floor the counterparty pays the Partnership. For the period from January 2004 through March 2004, the Partnership has floors in place at $3.50 on 1,426 Mmbtu of monthly production and ceilings in place at $5.26 on 1,426 Mmbtu of monthly production. For the period April 2004 through October 2004, the Partnership has floors in place at $3.20 on 1,782 Mmbtu of monthly production and ceilings in place at $4.70 on 1,782 Mmbtu of monthly production. As of December 31, 2003 the Partnership had option contracts for the sale of 16,574 Mmbtu of natural gas with an average ceiling price of $4.84 and for the sale of 16,474 Mmbtu of natural gas with an average floor price of $3.28. The fair value of open contracts as of December 31, 2003 is ($255).

The average NYMEX closing price for natural gas for the years 2003, 2002 and 2001 was $5.39 per Mmbtu, $3.22 per Mmbtu, and $4.27 per Mmbtu with a range from $1.83 per Mmbtu to $9.98 per Mmbtu. The average NYMEX closing price for oil for the years 2003, 2002 and 2001 was $30.98 per bbl, $26.98 per bbl and $26.60 per bbl with a range from $17.72 per bbl to $36.79 per bbl. The average CIG closing price for natural gas for the years 2003, 2002 and 2001 was $4.04 per Mmbtu, $1.97 per Mmbtu, and $3.50 per Mmbtu, with a range from $1.05 per Mmbtu to $8.63 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, 2003, 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 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY.

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 2003 has been filed with the Securities and Exchange Commission.

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. The following table presents compensation or reimbursements by the Partnership to PDC or other related parties during the periods ended December 31, 2003 and 2002 and period from November 9, 2001 (date of inception) to December 31, 2001.

	December 31,		Period from November 9, 2001 (date of inception) to December 31,
	2003	2002	2001
Drilling and completion costs	$ -	199,371	11,557,116
Syndication costs*	-	-	1,115,860
Management fee			265,681
Lifting costs	527,952	335,536	-
Tax return preparation	6,927	4,175	4,680
Direct administrative cost	4,086	2,840	1,369

* 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 reallowed or paid to the Soliciting Broker Dealers of the drilling program.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2003 and 2002 and period from November 9, 2001 (date of inception) to December 31, 2001, KPMG LLP provided auditing services in the amount of $3,126, $3,035 and $3,211, respectively. In the year 2001 KPMG LLP provided income tax services in the amount of $750.

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, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 10-K.

(a) (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.

(b) Reports on Form 8-K during the fourth quarter.

None.

(c) 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 25, 2001, of PDC 2003 Drilling Program, filed with the SEC on May 30, 2001).

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 Certification of Chief Executive Officer of Petroleum Development Corporation, the managing general partner of the Limited Partnership under Title 18 United States Code section 1350.

32.2 Certification of Chief Financial Officer of Petroleum Development Corporation, the managing general partner of the Limited Partnership under Title 18 United States Code section 1350.

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SIGNATURES

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

PDC 2001-C Limited Partnership
By its Managing General Partner
Petroleum Development Corporation

By /s/ Steven R. Williams
Steven R. Williams, Chairman
March 29, 2004

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
/s/ Steven R. Williams Steven R. Williams	Chairman, Chief Executive Officer, President and Director	March 29, 2004
/s/ Darwin L. Stump Darwin L. Stump	Chief Financial Officer and Treasurer (principal financial and accounting officer)	March 29, 2004
/s/ Thomas E. Riley Thomas E. Riley	Executive Vice President of Production , Natural Gas Marketing and Business Development and Director	March 29, 2004
/s/ Donald B. Nestor Donald B. Nestor	Director	March 29, 2004
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	March 29, 2004

PDC 2001-C 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, 2003 and 2002 and
Period from November 9, 2001
(Date of Inception)
to December 31, 2001

(With Independent Auditors' Report Thereon)

PDC 2001-C LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Index to Financial Statements

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.

Independent Auditors' Report

To the Partners
PDC 2001-C Limited Partnership:

We have audited the financial statements of PDC 2001-C Limited Partnership (a West Virginia limited partnership) as listed in the accompanying index. 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 auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits 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 audit provides 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 2001-C Limited Partnership as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years ended December 31, 2003 and 2002 and period from November 9, 2001 (date of inception) to December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 1 to the financial statements, the Partnership adopted the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations", in 2003.

KPMG LLP

Pittsburgh, Pennsylvania
March 15, 2004

PDC 2001-C LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Balance Sheets

December 31, 2003 and 2002

Assets

	2003	2002
Current assets:		
Cash	$ 1,967	1,070
Account receivable - oil and gas revenues	268,912	334,473
Total current assets	270,879	335,543
Oil and gas properties, successful efforts method (notes 3 and 5):	11,764,033	11,756,487
Less accumulated depreciation, depletion and amortization	2,169,418	1,242,841
	9,594,615	10,513,646
	$9,865,494	10,849,189

Liabilities and Partners' Equity

Current liabilities:		
Accrued expenses	$ 13,120	14,296
Total current liabilities	13,120	14,296
Asset retirement obligation	8,478	-
Partners' equity	9,843,896	10,834,893
	$9,865,494	10,849,189

See accompanying notes to financial statements.

PDC 2001-C LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Operations

Year Ended December 31, 2003 and 2002 and
Period from November 9, 2001 (Date of Inception) to December 31, 2001

	2003	2002	2001
Revenues:			
Sales of oil and gas	$2,104,889	1,741,435	-
Interest income	993	666	6,798
	2,105,882	1,742,101	6,798
Expenses (note 3):			
Management fee	-	-	265,681
Lifting costs	527,952	335,536	-
Independent engineering fee	-	3,006	3,000
Independent audit fee	3,126	3,035	3,211
Tax return preparation	6,927	4,175	4,680
Direct administrative cost	4,086	2,840	1,369
Depreciation, depletion and amortization	926,200	1,242,841	-
	1,468,291	1,591,433	277,941
Income (loss) before cumulative effect of change in accounting principle	637,591	150,668	(271,143)
Cumulative effect of change in accounting principle	(829)	-	-
Net income(loss)	$ 636,762	150,668	(271,143)
Net income (loss) per limited and additional general partner unit before cumulative effect of change in accounting principle	$ 960	227	(508)
Cumulative effect of change in accounting principle	(1)	-	-
Net income(loss) per limited and additional general partner unit	$ 959	227	(508)

See accompanying notes to financial statements.

PDC 2001-C LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statements of Partners' Equity

Year Ended December 31, 2003 and 2002 and
Period from November 9, 2001 (Date of Inception) to December 31, 2001

	Limited and additional general partners	Managing general Partner	Accumulated Other Comprehensive Income	Total
Partners' initial capital contributions	$10,627,234	2,311,423	-	12,938,657
Syndication costs	(1,115,860)	-		(1,115,860)
Net loss	(270,051)	(1,092)		(271,143)
Balance December 31, 2001	9,241,323	2,310,331		11,551,654
Capital contribution		199,371		199,371
Distribution to partners	(855,354)	(213,837)		(1,069,191)
Comprehensive income:				
Net income	120,534	30,134		150,668
Change in fair value of outstanding hedging positions			2,391	
Reclassification adjustment for settled contracts included in net income			-	
Other comprehensive income			2,391	2,391
Comprehensive income				153,059
Balance December 31, 2002	8,506,503	2,325,999	2,391	10,834,893
Distribution to partners	(1,300,092)	(325,021)		(1,625,113)
Comprehensive income:				
Net income:	509,410	127,352		636,762
Change in fair value of outstanding hedging positions			(1,448)	
Reclassification adjustment for settled contracts included in net income (loss)			(1,198)	
Other comprehensive loss			(2,646)	(2,646)
Comprehensive income				634,116
Balance December 31, 2003	$7,715,821	2,128,330	(255)	9,843,896

See accompanying notes to financial statements.

PDC 2001-C LIMITED PARTNERSHIP
(A West Virginia Limited Partnership)

Statement of Cash Flows

Year Ended December 31, 2003 and 2002 and
Period from November 9, 2001 (Date of Inception) to December 31, 2001

	2003	2002	2001
Cash flows from operating activities:			
Net income (loss)	$ 636,762	150,668	(271,143)
Adjustments to reconcile net income (loss) to net cash used by operating activities:			
Depreciation, depletion and amortization	926,200	1,242,841	-
Cumulative effect of change in accounting principle	829	-	-
Accretion of asset retirement obligation	480	-	-
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable - oil and gas revenues	63,169	(332,082)	-
(Decrease) increase in due to - Managing General Partner	-	(109)	109
(Decrease) increase in accrued expenses	(1,430)	2,155	12,141
Net cash provided from (used by) operating activities	1,626,010	1,063,473	(258,893)
Cash flows from investing activities:			
Expenditures for oil and gas properties	-	(199,371)	(11,557,116)
Net cash used by investing activities	-	(199,371)	(11,557,116)
Cash flows from financing activities:			
Limited and additional general partner contributions	-	-	10,627,234
Managing General Partner contribution	-	199,371	2,311,423
Syndication cost paid	-	-	(1,115,860)
Distributions to partners	(1,625,113)	(1,069,191)	-
Net cash (used by) provided from financing activities	(1,625,113)	(869,820)	11,822,797
Net increase (decrease) in cash	897	(5,718)	6,788
Cash at beginning of period	1,070	6,788	-
Cash at end of period	$ 1,967	1,070	6,788

See accompanying notes to financial statements.

(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 2001-C Limited Partnership (the Partnership). The statements do not include any assets, liabilities, revenues or expenses attributable to any of the partners' other activities.

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, 2003 by the Managing General Partner's petroleum engineers and at December 31, 2002 and 2001 by 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 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 flow, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Revenue Recognition

Sales of oil and natural gas are recognized when the right and responsibilities of ownership passes to the purchasers and are net of royalties. The Partnership sold oil and natural gas to several entities of which two customers accounted for 66.7% and 28.3% of the Partnership's total oil and natural gas sales for the year ended December 31, 2003 and 43.4% and 43.5% for 2002, respectively.

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.

(Continued)

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 New York Mercantile Exchange. The costless collars and option contracts hedge committed and anticipated natural gas sales generally forecasted to occur within a 12 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 or forecasted transactions. 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 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, 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 the derivative is dedesignated as a hedging instrument, because it is probable that a forecasted transaction will not occur, a hedged firm commitment no longer meets the definition of a firm commitment, or the Partnership determines that designation of the derivative as a hedging instrument is no longer appropriate, hedge accounting will discontinue.

By using derivative financial instruments to hedge exposures to changes in commodity prices, the Managing General Partner exposes the Partnership 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 Partnership, which creates credit/repayment risk. The Managing General Partner minimizes the credit/repayment 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 generally accepted accounting principles. 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 the impairment of long-lived assets.

New Accounting Standards

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Partnership adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $7,169 and a related liability of $7,998 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $829.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS no. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights (leases) associated with extracting oil and gas intangible assets in the balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Partnership has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Partnership would be required to reclassify the historical cost of approximately $416,050 of mineral rights associated with developed oil and gas properties as of December 31, 2003 and 2002 out of oil and gas properties and into a separate intangible mineral rights assets line item. The Partnership's total balance sheet, cash flows and results of operations would not be affected since such intangible assets would continue to be amortized and assessed for impairment.

(2) Organization

The Partnership was organized as a limited partnership on November 9, 2001, 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 21.5 units of limited partner interests and 509.8617 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 years ended December 31, 2003 and 2002 and period from November 9, 2001 (date of inception) to December 31, 2001.

	Year Ended December 31, 2003	Year Ended December 31, 2002	Period from November 9, 2001 (date of inception) to December 31, 2001
Drilling and completion costs	$ -	199,371	11,557,116
Syndication cost			1,115,860
Management fee	-	-	265,681
Lifting costs	527,952	335,536	-
Tax return preparation	6,927	4,175	4,680
Direct administrative cost	4,086	2,840	1,369

(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 Operating Capital, in the costs and revenues of the Partnership.

Partnership Costs	Investor Partners(5)(6)	Managing General Partner (5)(6)
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%
Partnership Revenues		
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%

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(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.

(4) The Managing General Partner receives monthly reimbursement from the Partnership for their 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, will be 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 2003 there were no units purchased by PDC.

(5) 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:

	2003	2002	2001
Lease acquisitions at cost	$ 416,050	416,050	416,050
Intangible development costs	9,245,693	9,245,693	9,245,693
Well equipment	2,094,744	2,094,744	1,895,373
Capitalized asset retirement costs	7,546	-	-
	$11,764,033	11,756,487	11,557,116

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

	Year Ended December 31, 2003	Year Ended December 31, 2002	Period from November 9, 2001 (date of inception) to December 31, 2001
Costs incurred:			
Property acquisition costs	$ -	-	416,050
Development costs	-	199,371	11,141,066
	$ -	199,371	11,557,116

(6) 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, 2003 and 2002, the income tax basis of the partnership's oil and gas properties was $1,269,891 and $1,642,162, respectively.

(7) Supplemental Reserve Information (Unaudited)

Proved oil and gas reserves of the Partnership have been estimated at December 31, 2003 by the Managing General Partner's petroleum engineers and at December 31, 2002 and 2001 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:

Net Proved Oil and Gas Reserves (Unaudited)

	Oil (BBL)		
	2003	2002	2001
Proved developed reserves:			
Beginning of year	359,000	241,000	-
Revisions of previous estimates	(8,000)	152,000	-
New Discoveries and extensions			
Rocky Mountain Region	-	-	241,000
Production	(22,000)	(34,000)	-
End of year	329,000	359,000	241,000

	Gas (MCF)		
	2003	2002	2001
Proved developed reserves:			
Beginning of year	4,515,000	4,175,000	-
Revisions of previous estimates	670,000	783,000	-
New Discoveries and extensions			
Rocky Mountain Region	-	-	4,175,000
Production	(396,000)	(443,000)	-
End of year	4,789,000	4,515,000	4,175,000

(8) 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,		
	2003	2002	2001
Future estimated revenues	$ 33,505,000	25,241,000	14,842,000
Future estimated production costs	(7,940,000)	(5,914,000)	(4,140,000)
Future estimated development costs	(2,321,000)	(2,321,000)	(1,421,000)
Future net cash flows	23,244,000	17,006,000	9,281,000
10% annual discount for estimated timing of cash flows	(11,980,000)	(8,317,000)	(4,447,000)
Standardized measure of discounted future estimated net cash flows	$11,264,000	8,689,000	4,834,000

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

	Years Ended December 31,		Period from November 9, 2001 (date of inception) to December 31,
	2003	2002	2001
Sales of oil and gas production, net of production costs	$(1,577,000)	(1,406,000)	-
Net changes in prices and production costs	6,584,000	6,035,000	-
Extensions, discoveries, and improved recovery, less related cost	-	-	9,281
Revisions of previous quantity estimates	1,231,000	3,096,000	-
Accretion of discount	(3,663,000)	(3,870,000)	(4,447,000)
	$2,575,000	3,855,000	4,834,000

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flows 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.